Montan Universität Leoben

Department of Mineral Resources and Petroleum Engineering

Design and Optimization of Electrical Submersible Pumps (ESPs) in Libyan oil field.

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MASTER OF SCIENCE

Under supervision of Univ.Prof. Dipl.-Ing. Dr Herbert Hofstaetter

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Affidavit

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

Datum

Unterschrift

Kurzfassung

Das Hauptinteresse dieser Studie wird auf die Optimierung von ESPs in einem Ölfeld mit hohem Wasseranteil und niedrigem Lagerstätten-Druck gelegt, Infolge eine reduziert Erdölgewinnung resultiert. Der Zweck der Optimierung ist, einen höheren drawdown auf die Formation zu schaffen und verhältnismäßig mehr Produktion zu erreichen. Das Diplomarbeit behandelt sechs Bohrlöchern, die mit ESPs in einem Libyschen Ölfeld ausgerüstet worden sind, das sich im süd-west Teil von Sirte Becken befindet. Nodal Analyse wurde zwischen der Lagerstätte und dem Bohrlochskopf vorgenommen, ohne Berücksichtigung der installierten äußerlichen Einrichtungen , um eine wesentliche Produktionsoptimierung durchzuführen. PROSPER Software wurde benutzt, um die notwendigen Berechnungen durchzuführen. Optimierung wurde PROSPER durch zwei verschiedenes Fallszenarios simuliert, und dies mit dem eigentlichen jetzigen Fall vergleicht:

1. Analyse und Betr.-optimieren von der derzeitigen Pumpe mit dem aktuellen Durchfluss, in Absicht, der Reduktion der stufenzahl , und höheren Pumpenwirkungsgrad vergleichend zur jetzigen Pumpe.

2. Entwerfen Sie eine neue Pumpe mit höherer Produktionsrate und dem Versuch einer optimierten Pumpenabsetzteufe.

Zusätzlich wurde eine Empfindlichkeitsanalyse durchgeführt, basierend auf der Wirkung des wachsenden Wasseranteils während der Lebenszeit des Bohrlochs, auf die Fähigkeit der Lagerstätte , Flüssigkeiten zur Oberfläche zu liefern. Eine Ökonomische Analyse wurde durchgeführt, zukünftige Cashflows, und Gewinn oder Verlust von erwähnten Szenarios abzuschätzen. Die Berechnung wurde geleitet von: NPV (Cumulative Discounted Net Cash Flow) und Payout Time. Die Ergebnisse haben gezeigt, dass die verwendung des zweiten Fall szenario führt zu einer Erhöhung des NPV von 52% im Vergleichen zu anderen Fällen führt.

Abstract

The major interest of this study is focused on Electrical submersible pumps optimization in oil field suffering from increasing in water cut ,decreasing in reservoir pressure and as a result reduction in oil production for the purpose of creating a higher drawdown on the formation and achieving comparatively more production. The study covers 6 wells equipped with ESPs in one of Libyan oil field located in South Western part of Sirte basin. Nodal analysis approach was applied between the reservoir and the wellhead ignoring the surface facilities in order to carry out the essential production optimization.

PROSPER software was used to perform the necessary calculations. Production has been simulated in PROSPER through two different cases scenario comparing with the actual current case:

1. Analysis and Re-optimizing of the present pump at the same producing flow rate in the intention of getting reduction in number of stages and higher pump efficiency comparing to the current pump.
2. Design a new pump with more production rate taking into account the capability of the well and trying to achieve optimum pump setting depth.

Additionally, sensitivity analysis was carried out based on the effect of rising water cut percentage over well life time on the ability of a reservoir to deliver fluids to the surface.

In order to evaluate the mentioned different scenarios, economical analysis was done to estimate future cash flows and to have an assessment of profit or loss.

The main profit indicators were used are: Net Present Value (Cumulative Discounted Net Cash Flow) and PayOut time. The results showed that applying second case senario will increase the profit up to 52 % comparing to the current and first case senario.

Dedications

This thesis is dedicated to my parents, who taught me that even the largest task can be achieved if you are insist on finish it.

And

It is dedicated to my husband who supported me and enabled such a study to take place today

Acknowledgements

I am heartily thankful to my supervisor, Professor Herbert Hofstaetter, whose encouragement, guidance and support from the initial to the final level enabled me to develop an understanding of the subject.

I also offer my regards and blessings to all those who supported me in any respect during the completion of the project especially my sisters.

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Intesar Elagil

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CHAPTER 1

Introduction

1.1. Background:

The ESPs are widely utilized as an artificial lift system due to their high efficiency and compact design. They are easy to install and operate and they can lift extremely high volumes from highly productive oil reservoirs. Crooked/deviated holes present no problem. ESPs are applicable to offshore operations. Lifting costs for high volumes are generally very low. The ESP literally works submersed into the fluid, since it is installed within a cased hole well from which the oil is produced. Because the ESP pumps are centrifugal pumps, liquid viscosity and free gas can affect their performance.

A submersible pumping unit consists of an electric motor, a seal section, an intake section, a multistage centrifugal pump, an electric cable, a surface installed switchboard, a junction box and transformers. Additional miscellaneous components also present in order to secure the cable alongside the tubing and wellhead supports. The Pumps themselves are made of dynamic pump stages or centrifugal pump stages which are serially mounted. The overall ESP system operates like any electric pump commonly used in other industrial applications. The electric energy is transported to the down-hole electric motor via the electric cables. These electric cables are run on the side of (and are attached to) the production tubing. The electric cable provides the electrical energy needed to actuate the down-hole electric motor. The electric motor drives the pump and the pump imparts energy to the fluid in the form of hydraulic power, which lifts the fluid to the surface.

1.2. Objective:

Due to the fact that many oil and gas wells that lifted by ESPs produce at flow rates different than optimum rate, the main target in this thesis is to suggest optimum submersible pump running conditions for each well to continue production in a more economical and cost saving approach. This will be applied on 6 wells belongs to a Libyan field which have low production rates and consequently low productivity.

The purpose of this study can be achieved as following:

1. Review the current pumps operating conditions of the 6 ESP lifted wells
2. Re-sizing ESP system subsurface components for the 6 selected wells by applying different scenarios with the aim of achieving the optimum setting depth and the optimum flow rate ,also an optimum required horsepower and number of pump stages at this rate.
3. In addition to that, application of sensitivity analysis approach believing that the main properties of these wells are changed over life time of the field which could influence the performance of ESPs.

1.3. Methodology:

PROSPER software is one of the Integrated Production Modeling toolkit (IPM) suite which was used in this thesis with the aim of achieving the previous mentioned objectives. The software facilitates designing and optimizing wells with ESP lifting system from the reservoir up to the well head.

Detailed information and procedures were used and results were obtained are described in chapter 5 and 6 correspondingly. Moreover, after the design steps, economical evaluation of the new ESPs design applications were examined.

CHAPTER 2

Description of the X Field in Libya

2.1 Historical Background and Geology

The selected field is located in the South Western part of Sirte basin. It was discovered in 1978 and has been on production since then .The field has multiple reservoirs all related to the same individual geological structural feature and these reservoirs are structural high, covering more than 6000 acres. The field is mostly fault closures on the western margin of tilted fault blocks. The most striking feature of the selected field is the NW-SE trending faults .The field is characterized by Palaeocene/Eocene petroleum system and the lithology is mainly dolomite with some anhydrite intercalations in the upper part and increasing limestone towards the bottom of the reservoirs.

The Predominant drive mechanism under primary depletion is considered to be solution gas drive although some water influx is anticipated. Crude is sour, and of approximately 40 API degrees. The field consists of more than 100 drilled wells where there are more than 70 wells on production up to now. The others is either temporarily closed or plugged and abandoned. Because of a steep pressure decline in wells that was observed during production, it was decided that the field pressure should be maintained by water injection. The injection water is derived from a saline water source just west of the field location. Also, all the water produced is re-injected. Both water streams are conditioned in a water treatment plant prior to (re-injection) ensuring high water quality. The field has more than 30 injection wells. The average reservoir pressure was about 2300 psig and this value was depleted to be between 1390 and 1645 psig, consequently there was a need to use an artificial lift system to enhance oil recovery of the field. Since 2003, electrical submersible pumps are installed in about 50 wells.

2.2 Field Production History

Figure (2-1) gives an overview of the oil and water production flow rate in the field during the period from 1980 to 2009. It is apparent that water production volume is increasing with time for the entire field.

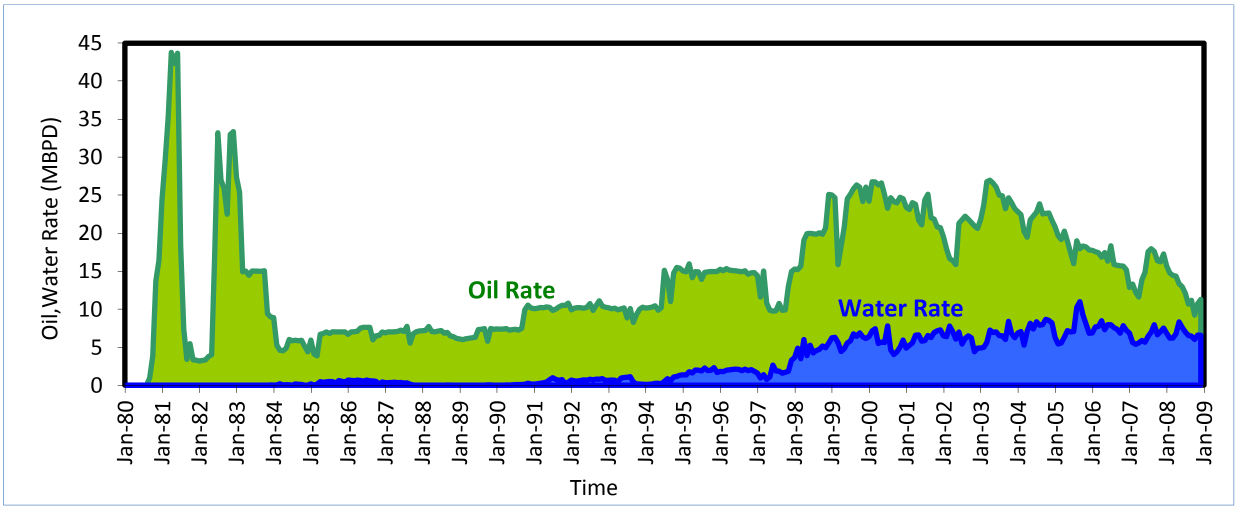

Figure (2-1) Oil and Water Production Rate History

2.3 Reservoir and Fluid properties

The field under the study is characterized by having light crude oil and low gas oil ratio. The general reservoir fluid and rock properties are presented in **Table (2-1).**

Reservoir and Fluid properties	
Oil Gravity, (API)	40
Water Specific Gravity (Sp.Gr.)	1.1
Gas Specific Gravity (Sp.Gr.)	0.855
Water Salinity, (ppm)	88000
Bubble Point Pressure ,Psi	486
Reservoir Temperature, F^{o}	144
Average Reservoir Porosity,%	20-24

Table (2-1) Average reservoir fluid and rock properties rock

2.4 Lifting system characterization

All electrical submersible pumps installed on wells have been provided by the same vendor which is REDA. Number of wells in this study is 6 wells lifted with electrical submersible pumps

and **Table (2-2)** presents the pumping unit types, some of their features and the gross flow rate achieved by these pumps. A study was conducted during the period from 2001 to 2008 to investigate the ESP failure mode in the selected field hence, **Figure (2-2)** shows that motor problems were the highest percentage in causing ESP failure.

Well name	Series	Model Currently Pump Used	Liquid Flow Rate, bbl/day	Pump Stages	Pump Efficiency,%
X-1	400	D725N	750	158	56.3
X-2	400	D725N	882	115	53.4
X-3	400	DN675	500	159	57.9
X-4	400	DN1000	819	229	52.2
X-5	400	DN280	250	319	43.7
X-6	400	D475N	366	158	50.7

Table (2-2) Electrical submersible pumps features

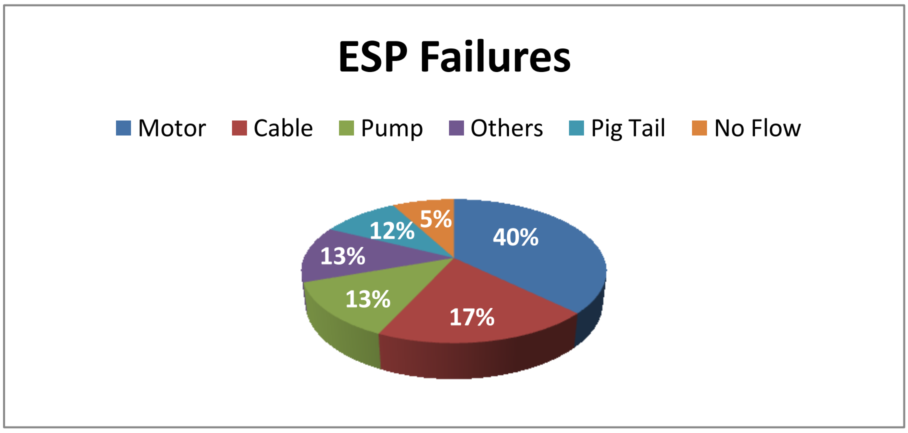

Figure (2-2) Electrical submersible pumps Average Percentage Failures mode

CHAPTER 3

Electrical Submersible Pump System

3.1 Components of Electrical Submersible Pump System

The ESP system can be divided into subsurface and surface components. The major downhole components include an electric motor, seal section, multi-stage centrifugal pump with an Intake and discharge and power cable. Optional downhole equipment may include a bottomhole pressure/temperature sensor check, drain valves motor shroud and a gas separator. The surface components include a junction box, switchboard and transformers. A typical ESP installation is shown in **Figure (3-1).** A description of each component is given below, beginning downhole and moving up the well.

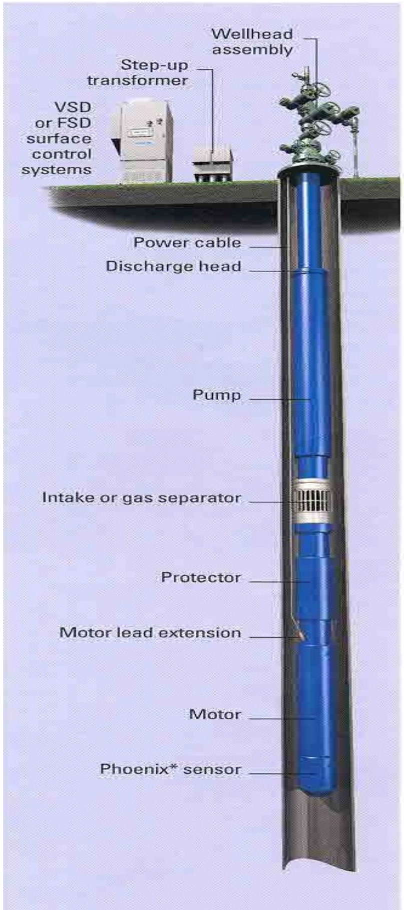

Figure (3-1) surface and subsurface ESP installation **[1].**

3.1.1. Motor:

The electric motors used in submersible pumps operations are two pole, three phase, squirrel cage, induction type.

- These motors rotate at 2900 rpm on 50 Hz or 3475 rpm on 60 Hz.
- Their design and operating voltage can be as low as 230V or as high as 5000 V.
- Amperage requirement may be from 12 to 110 A
- The efficiency of submersible motors runs from 80% to 90%.

Motors are filled with non conductive oil with a high dielectric strength which provides lubrication for bearings and good thermal conductivity. Produced fluid moving past the outside of the motor carries heat away; cooling the motor (minimum recommended fluid velocity is 1 ft/sec). If the fluid velocity is not sufficient to cool the motor, or if the motor is located below the perforations, the shroud should be placed around the motor **[2], [3].**

3.1.2. Seal, Protector, Equalizer:

The seal section (also known as a protector or equalizer) is located between the motor and fluid Intake of the pump. The seal performs four basic functions:

- Connect the pump housing to the motor housing by connecting the drive shaft of the motor to the pump shaft.
- House the pump thrust bearing.
- Seal the power end of the motor housing from the wellbore fluids while allowing pressure communication between motor and wellbore fluids.
- Provide the volume necessary for the expansion of the unit's oil due to heat generated when the motor is in operation, **[3].**

3.1.3 Pump:

The submersible pumps used in ESP installations are multistage centrifugal pumps; each stage consists of rotating impeller and stationary diffuser. Pressure- energy change is achieved as the liquid being pumped surrounds the impeller, and as the impeller rotates it gives a rotating motion to the liquid. The pump operating in a vertical position. Although their constructional and operational features underwent a continuous evolution over the years, their basic operational principle remained the same, **Figure (3-2)** shows the main parts of ESP pump. The pump shaft is connected to the gas separator or the protector by a mechanical coupling at the bottom of the pump. Well fluids enter the pump through an intake screen and are lifted by the pump stages. Other parts include the radial bearings (bushings) distributed along the length of the shaft providing radial support to the pump shaft turning at high rotational speeds. An optional thrust bearing takes up part of the axial forces arising in the pump but most of those forces are absorbed by the protector's thrust bearing **[2], [4].**

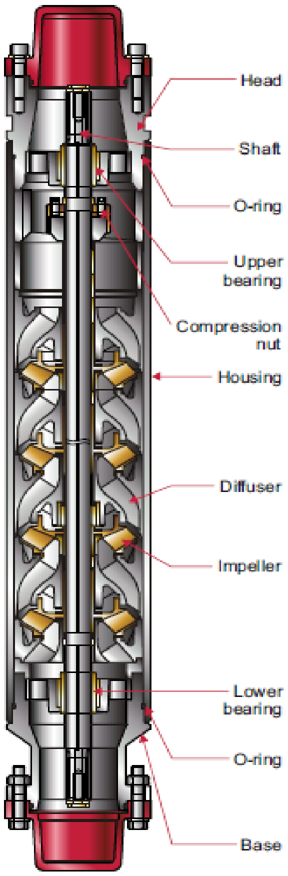

Figure (3-2) Main parts of ESP pump, **[4].**

Conventional ESP installations run on AC power with a constant frequency of 60 Hz or 50 Hz. ESP motors in 60 Hz electrical systems rotate at a speed of about 3,500 RPM, whereas in the case of a 50 Hz power supply the motor speed is about 2,900 RPM. For constant speed applications the most important factor is impeller size which, of course, is limited by the ID of the well casing. Pumps of bigger sizes can produce greater rates although impeller design also has a great impact on pump capacity. Present-day ESP pumps come in different capacities from a few hundred to around 80,000 bpd of liquid production rate and in outside diameters from around 3 in up to 11 in. Smaller units contain pancake-type impellers with radial discharge and are used up to the rates of 1,500–3,500 bpd, above which mixed flow impellers are used. The length of individual ESP pumps is limited to about 20–25 ft, for ensuring proper assembly and ease of handling. Tandem pumps are made up of several pump sections (up to three) and are used to achieve higher operational heads usually required in deeper wells. This way several hundreds of stages can be run, the maximum number of stages being limited by one or more of the following factors:

- The mechanical strength of the pump shaft, usually represented by the shaft's horsepower rating,
- The maximum burst-pressure rating of the pump housing.
- The maximum allowed axial load on the unit's main thrust bearing (usually situated in the protector section).

Individual stages in ESP pumps, provided they are of the same impeller design, handle the same liquid volume and develop the same amount of head. The heads in subsequent stages are additive so a pump with a given number of stages develops a total head calculated as the product of the total number of stages and the head per stage. This rule allows one to find the number of stages required to develop the total head to overcome the total hydraulic losses, valid at the desired liquid production rate in a well.

3.1.3.1. Pump Performance Curves

Pumps are divided into groups according to the minimum casing size into which the pump can be run. But even within the same group, each pump performs differently. A typical pump performance curves is given in **Figure (3-3).**

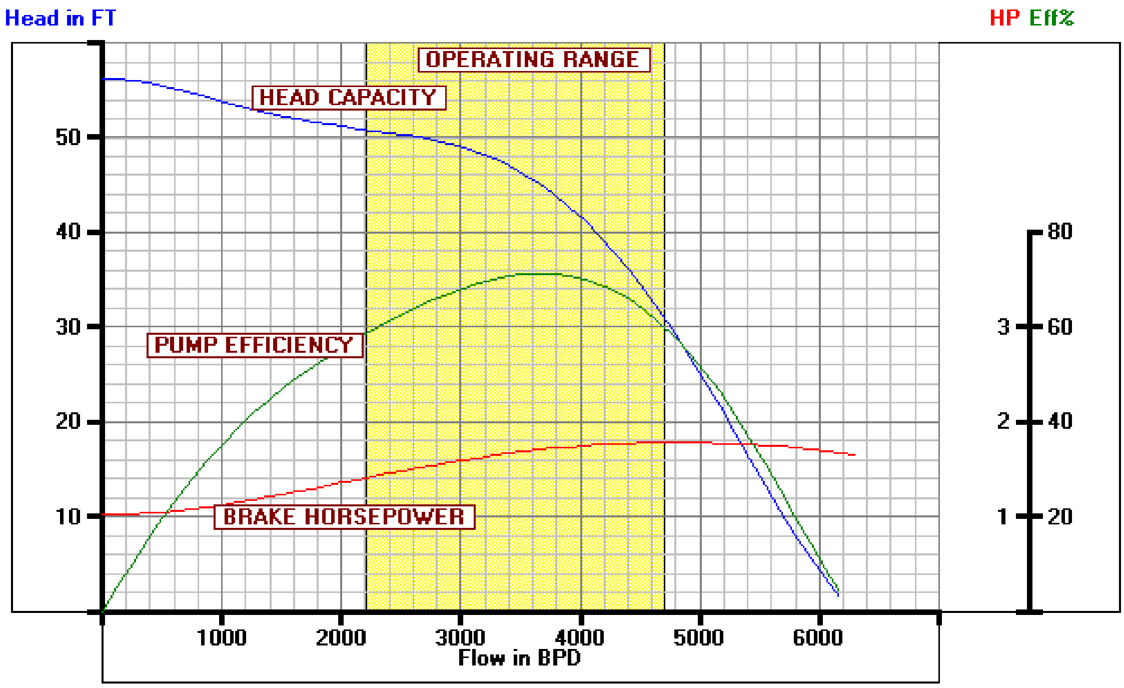

Figure (3-3) typical pump performance curves, **[5].**

In Figure (3-3) the performance parameters belonging to the best efficiency point (BEP) represent the criteria for an optimum utilization of the pump, around which the recommended range of operation is indicated. The recommended range of pumping rates for any ESP pump is strictly related to the variation of axial forces occurring in the pump.

In fact there are three main forces acting on the impeller during normal operation:

- Downward force of gravity that acts on top of the impeller, pushing it down.
- The resultant force from the differential pressures between the top and the bottom of the stage.
- The force from the velocity of fluid that flows through the impeller.

The resultant of these forces determines whether the stage is working upthrust, downthrust or in a balanced state. The proper selection of the stage and handling of the thrust forces is very important for the reliability and the performance of the pump. As a rule of thumb, a pump operating below the lower range of the recommended operation range is said to be running in downthrust and that operating above the upper range of the recommended operation range is said to be running in upnthrust **[6]**.

The performance curves of a submersible electrical pump represent the variation of head, horsepower, and efficiency with capacity. Capacity refers to the volume of the produced flow rate, which may include free and/or dissolved gas. These curves are for a fixed power cycle – normally 50 or 60 cycle – and can be changed with variable frequency controllers.
The head (in feet per stage) developed by a centrifugal pump is the same regardless of the type or specific gravity of the fluid pumped. But when converting this head to pressure, it must be multiplied by the gradient of the fluid in question. Therefore, the following can be stated **[7]**:

$$\text{Pressure developed by pump (Psi)} = \text{Head per stage} \times grad_f \times \text{Number of stages}$$

Where:
$grad_f$= Fluid gradient, psi/ft

The pump performance curves give the horsepower per stage based on a fluid specific gravity equal to 1.0. This horsepower must be multiplied by the specific gravity of the fluid under consideration. Thus the following can be stated:

$$\text{Horsepower Requirements (HP)} = \frac{Horsepower}{\text{Stage}} \times \gamma_f \times \text{stages}$$

Where:
$\gamma f = \text{specofic gravity of fluid}, -$

For each pump, there is a capacity range within which the pump performs at or near its peak efficiency. The volume range of the selected rate between the intake and the discharge pressures should, therefore, remain within the efficiency range of the pump. This range, of course, can be changed by using a variable speed drive (VSD).

3.1.4 The Gas Separator:

The simplest and least efficient gas separator has been in use almost since the early days of ESP operations is called the reverse flow gas separator; **Figure (3-4).** It may also act as an intake for the centrifugal pump and can separate low to moderate amounts of gas with a limited efficiency. The separator is connected between the protector and the pump and directs the separated gas into the well's casing/tubing annulus. It is, therefore, essential that the conventional installation should be used where the casing annulus is not sealed off by a packer. It works on the principle of gravitational separation by forcing the fluid flow to change direction and allowing free gas to escape into the well's annulus. Well fluid containing free gas bubbles enters the separator through the perforated housing. In the annular space formed by the housing and the stand tube, gas bubbles raise but liquid flows downward. If bubble rise velocity is greater than the countercurrent liquid flow velocity, gas bubbles rise to the top of the separator and escape into the well's annulus through the upper perforations of the separator's housing. Liquid containing a reduced amount of free gas is sucked in by the pickup impeller at the bottom of the separator and is transferred to the ESP pump connected to the top.

In high gas oil ratio wells the rotary gas separator is used to remove the free gas from the produced fluid. By venting this gas to annulus, the separator prevents cycling, gas lock and cavitations resulting in a stable motor load and increased run life; **Figure (3-5).**

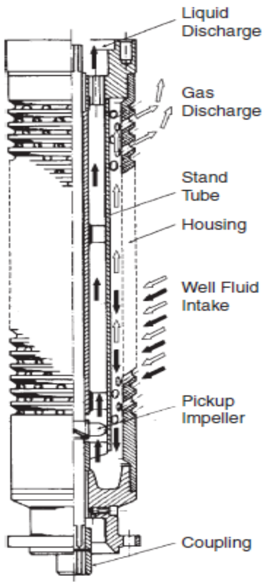

Figure (3-4) Reverse flow Gas separator **[2].**

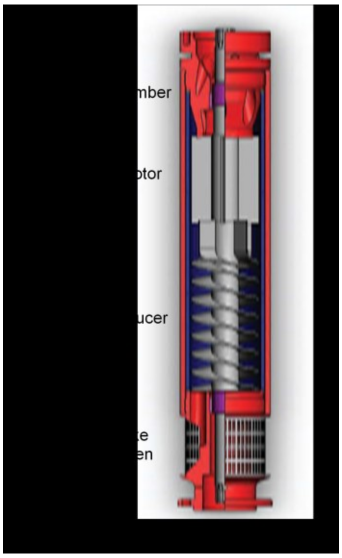

Figure (3-5) Rotary Gas separator **[7].**

3.1.5 The Power Cable:

Three phase electric cables are used to transmit power from surface to submersible motor. They must be small in size and well protected from aggressive well environment. As a limited space available between casing and equipment flat types can be used.

ESP power cables are complex structures with the following structural parts:

- The three metal (usually copper) conductors carrying the AC current.
- The individual insulation of each conductor preventing short circuits and leakage currents between the conductors.
- The jacket, the protective cover of the three conductors that provides the structural strength and mechanical protection of the cable and prevents contact of the insulations with the downhole environment.
- Supplementary coverings over the insulation providing additional strength and protection to cable components.
- A metal armor (optional) providing enhanced mechanical protection during running and pulling operations as well as reducing the swelling (due to contact with well fluids) of underlying insulator materials.

- **Cable construction:**

ESP cables are available in two configurations: round or flat, **Figure (3-6)** and **Figure (3-7)** illustrate a construction of Round cable and flat cable respectively. Round cables are generally used along the tubing string where annular space is not too critical and the cable can fit between the tubing coupling OD and the casing's drift diameter. On the other hand, flat cables with a much smaller radial space requirement are necessary for small annular configurations or along the ESP unit whose outside diameter is considerably greater than that of the tubing string.

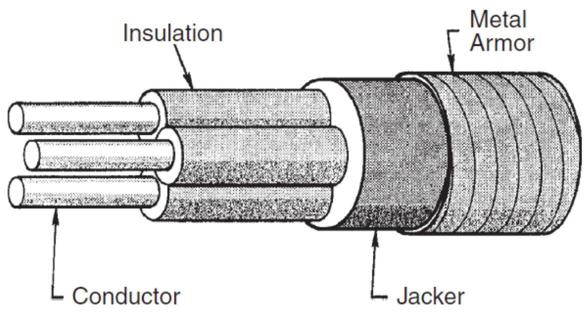

Figure (3-6) a typical construction of Round cable **[2].**

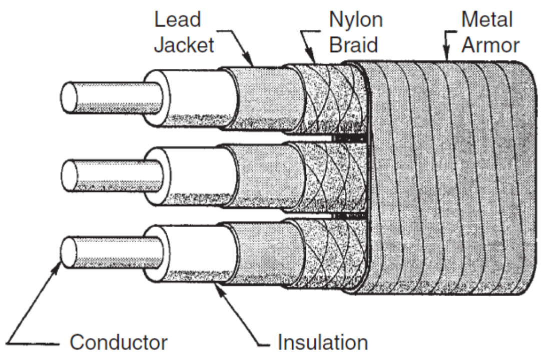

Figure (3-7) a typical construction of Flat cable **[2].**

3.1.6. Check Valve: A check valve is used to prevent the reverse rotation of the subsurface unit when motor is shut off. If this unit is not installed a leakage of fluid down the tubing through the pump occurs which can be results cable burn or broken shaft.

3.1.7. Drain Valve:

This device is generally used with check valve placing above it. As check valve holds a column of fluid above the pump, the risk of pulling a wet tubing string occurs. Drain valve prevent the fluid to come up while pulling the downhole units.

3.1.8. Centralizer:

It is used **e**specially in deviated wells to eliminate damage and obtain the proper cooling of the equipment. And also it is used to place the motor and pump in the centre of the wellbore. It also uses to prevent rubbing of power cable against the casing string.

3.1.9. Well Head:

For ESP installations special wellheads are used to support the weight of the subsurface equipment and to maintain annular control. They have to provide a positive seal not only around the tubing but around the cable as well.

3.1.10. Junction Box:

The power cable coming from the well should be connected to a surface electric cable leading to the switchboard. As seen in **Figure (3-8),** the two cables are joined in the junction box, also called a “vent box.” It is a ventilated, weatherproof box performing the following three important functions:

- It provides the electrical connection between the downhole and the surface electric cables.
- It vents any gas to the atmosphere which might reach this point due to migration of well gases up the ESP power cable. The venting of gas eliminates the danger of fire or explosion because gas is not allowed to travel in the cable to the switchboard.
- It acts as an easily accessible test point for electrically checking the downhole equipment.

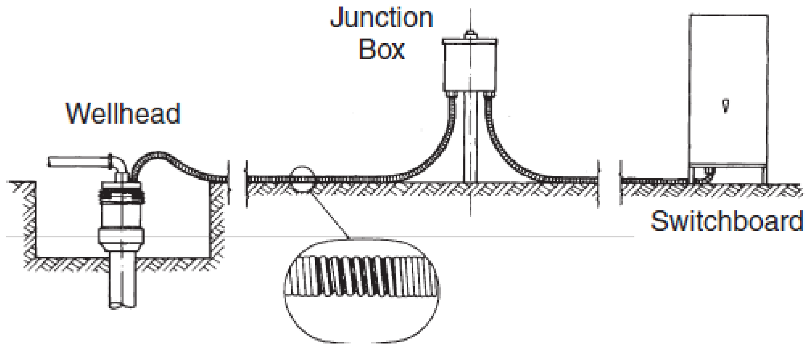

Figure (3-8) surface arrangement of ESP installation **[2].**

3.1.11. Switchboard:

The switchboard is the control center of a conventional ESP installation and acts as a motor controller and, consequently, controls the operation of the whole installation. It has the following functions:

- provides a controlled on/off switching of the ESP equipment to the power
- supply using high capacity switch disconnectors or vacuum contactors,
- Protects the surface and downhole equipments from a wide variety of problems, and
- Monitors and records the most important operating parameters.

3.1.12. Transformers:

In the majority of cases, the available surface voltage is not compatible with the required motor voltage and transformers must be used to provide the right voltage level on the surface. Power distribution in the oilfield is at voltages of 6,000 volts or higher, while ESP equipment operates at voltages between around 250 and 4,000 volts. Transformers for ESP installations are oil-filled, self-cooling units and are available in three-phase standard; three-phase autotransformer configurations or a bank of three single-phase transformers can be used. At higher primary voltages, the use of three single-phase transformers is more economical than that of a three-phase transformer. Transformers are selected on the basis of voltage levels and power ratings. The required surface voltage heavily depends on the setting depth of the ESP equipment since the voltage drop in the power cable increases with cable length. This voltage drop plus the selected motor voltage give the necessary surface voltage.

3.1.13. Variable Speed Drive (VSD) :

The Variable Speed Drive is becoming more common with ESP installations as the understanding of VSD technology with downhole ESP applications improves. The advantage of a VSD is that it increases the optimum operating range of any ESP. The disadvantage is that in order to change the frequency VSD's manipulate incoming power through a series of ultra high speed switching which can create disturbances in the power system both to the ESP and back onto the power grid or gen-set.

These disturbances are known as harmonics. It is impossible to determine the level of harmonics with standard electrical instrumentation. A power spectrometer is required and is normally set up on a well for a few days to get an idea of the harmonic being generated. It is surprising how much work can go into the evaluation of downhole equipment and the reservoir, but rarely is the power supply reviewed. Often great gains in run life can be made in this area, **[9].**

3.2. Electrical Submersible Pump Pros and Cons, [2].

General advantages of using ESP units can be summed up as follows:

- Ideally suited to produce high to extremely high liquid volumes from medium depths. Maximum rate is around 30,000 bpd from 1,000 ft.
- Energy efficiency is relatively high (around 50%) for systems producing over 1,000 bpd.
- Can be used in deviated wells without any problems.
- Requires low maintenance, provided the installation is properly designed and operated.
- Can be used in urban locations since surface equipment requires minimal space.
- Well suited to the offshore environment because of the low space requirements.
- Corrosion and scale treatments are relatively easy to perform.

On the other hand, General disadvantages are listed below:

- A reliable source of electric power of relatively high voltage must be available.

- The flexibility of ESP systems running on a constant electrical frequency is very low because the centrifugal pumps liquid producing capacity practically cannot be changed. Proper installation design based on accurate well inflow data and matching the unit's capacity to well deliverability is crucial, otherwise costly workover operations are required to run a new unit in the well. The use of variable speed drives can eliminate most of these problems but at an extra cost.
- Free gas present at suction conditions deteriorates the submersible Pump's efficiency and can even totally prevent liquid production. The use of gas separators or gas handlers is required if more than 5% of free gas enters the pump.
- Sand or abrasive materials in well fluids increase equipment wear. Special abrasion-resistant materials are available but increase capital costs.
- Repair of ESP equipment in oilfield conditions is difficult, faulty equipment must be sent to the manufacturer's repair shop.
- High well temperature is a limiting factor, standard equipment is limited to about 250 F, and use of special materials increases the temperature limit to 400 F.
- Production of high viscosity oils increases power requirements and reduces lift.
- Running and pulling costs are high because of the need for heavy workover rigs. Cable suspended or CT (coiled tubing) deployed ESP units reduce workover costs.

Applications

3.2.1. Shrouded Configuration:

Shrouds are defined as a short section of pipe around the length of the ESP unit that has been successfully used to:

- Act as simple reverse flow gas separators which, by changing the direction of flow, allow the buoyancy effect to decrease the amount of free gas that enters the pump, and
- Provide liquid flow along the ESP motor's length to ensure proper cooling of the unit. The simplest "open ended" shrouded installation is depicted in **Figure (3-9),** where the ESP unit is run below the perforations. The motor shroud is hanging from above the pump intake and forces well fluids to flow downward in the casing/shroud

annulus. The annular space must have a sufficiently large cross-sectional area to ensure a low (preferably less than 0.5 ft/sec) fluid velocity so that gas bubbles may rise and be vented up the casing annulus.

The shroud also guarantees that produced fluids flow along the motor's length thus providing proper cooling.

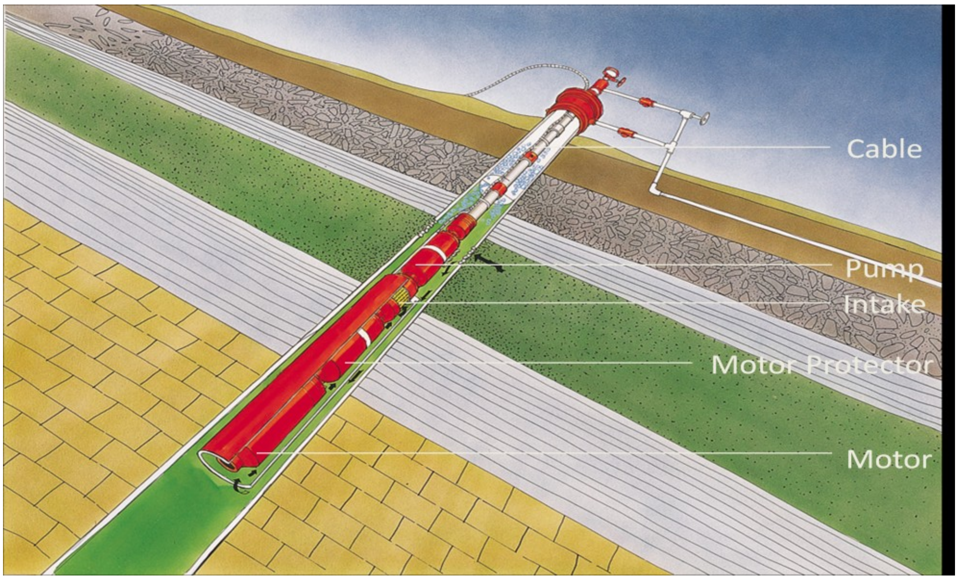

Figure (3-9) typical shrouded ESP installation, **[10].**

3.3.2. Y –Tool:

The Y-tool application, **Figure (3-10),** is designed to allow access to the reservoir with an ESP in the well by including a by-pass tube and hanging the ESP off to the side of the main tubing string. With a Y-tool perforations can be added, logs can be run – it is even possible to run a spinner survey with the ESP in operation. The standard Y-Tool assembly has three major parts; 1) the tool itself, designed to allow flow from the pump into production string with minimum al flow restriction, 2) a blanking plug, standing valve or logging plug is used to isolate the by -pass tubing when the well is on production, and 3) the by- pass tubing itself, which is securely attached to the ESP assembly **[17]**.

Figure (3-10) Y-tool **[9].**

3.3.3. Parallel-connected Installations:

Deploying two ESP's in a well at the same time allows for the existence of a redundant ESP system which in turn leads to extended run life of the system. This results in reduced workover costs in the long term and minimizing "lost revenue" from deferred oil production whilst enabling scheduling for a workover program. **Figure (3-11)** shows the two ESP systems are connected to the tubing string with two "Y-tools," which make it possible to select between the two ESP systems **[11].**

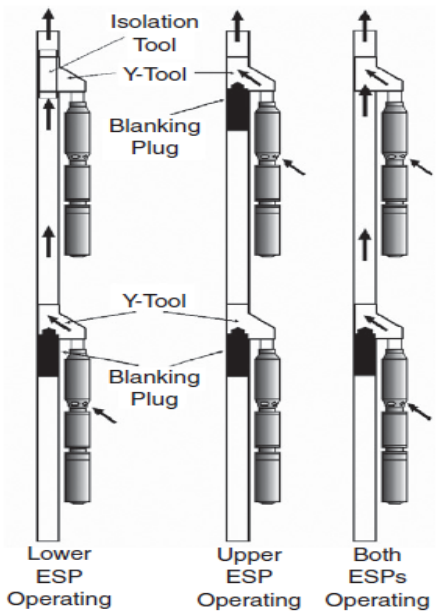

Figure (3-11) Parallel installation of two ESP units, **[2].**

3.3.4. Coiled Tubing Deployed ESP:

Over half the ESP failures worldwide occur in the cable string. If there was a way to remove the cable from the well bore, the major cause for ESP failure would be eliminated. Coil tubing deployed ESPs achieve just that. The electrical cable is housed inside the coiled tubing and the ESP is lowered on the coiled tubing. In this case production occurs between the coiled tubing and liner. Due to this configuration the standard installation of Pump on top, Motor on the bottom no longer needs to be followed. Most Coiled Tubing ESPs have the motor on the top and the pump on the bottom.

The major advantage of this configuration is that a workover rig is not required to pull and run – this is done with a coiled tubing unit. Also, the pulling and running time is significantly less with coiled tubing.

The major hurdle in using coiled tubing deployed ESPs is the weight of the coil/cable reel and often crane limitations offshore prevent this type of installation from being considered, **[9].**

3.3.5. Booster Pump:

An electric pump used as a boaster pump to increase the incoming pressure when too long pipelines are in consideration. Unit set in a shallow set vertical section of casing. An incoming line is connected to the casing feeds fluid into the casing and pump. If pumps connected in series flow rate will be constant while pressure increases. If pumps connected in parallel pressure will be the same while production rate increases.

3.3.6. ESP Installation with Deep Set Packer:

In case of dual production zone or cable damage problem because of gas saturation in high pressure well ESP installation with packers can be used. In this application an electrical feed placed in the packer using prefabricated connections.

3.4. Design of Electrical Submersible Pump

3.4.1. Gather Base Data:

For a proper design of an ESP installation, knowledge of many different data is necessary. Perhaps the most important among them is the reliable information on the well's productivity so that the desired fluid rate from the well can be established. The fluid rate is always an input parameter in the design of ESP installations because the selection of the submersible pump (the heart of the system) can only be accomplished in the knowledge of the desired rate. The data elements required for an ESP design can be segregated into six categories:

- General Information: Identifies the well and who collected the data on what date.
- Wellbore Geometry: Describes well trajectory and completion equipment details.
- Surface Information: Describes surface equipment and conditions.
- Fluid Properties: Describes the fluid produced by the well and chemicals introduced for deposition prevention and corrosion.
- Inflow Characteristics: Contains data elements that describe the well's productivity. This data is critically important in an ESP design. Care should be taken that this data is as accurate as possible.
- Design Criteria specifies the desired performance from the ESP installation.

The first five categories define the environment in which the ESP will operate. The sixth category defines the operating parameters desired by the well operator. Additional information that may be of use to the ESP designer includes wellbore schematics, PVT reports, gas and oil composition reports, and water analysis reports. ESP failure analyses, amp charts, and workover reports on prior ESP installations from the well of interest or offset wells can also provide valuable design clues.

3.4.2. Conventional Design:

Designing an ESP installation for a well that produces liquid only is a quite straightforward procedure because the operating conditions for the submersible pump are ideal and simple hand calculations suffice to describe the pressure conditions in the well. In any other situation, however, the use of a computer is almost a must because of the increased calculation demand.

3.4.2.1. Well inflow Calculations:

It is important to know the liquid flow rate and the corresponding dynamic liquid level before getting on the prober ESP installation depending on whether free gas is present at the perforations or not, we have either the constant productivity index (PI) or the Vogel model can be applied. The well's flowing bottomhole pressure (Pwf) is easily calculated from the following formulas

- If the constant PI equation describes the well inflow:

$$\mathrm{Pwf} = \mathrm{PR} - \frac{\mathrm{q}}{\mathrm{PI}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3-1$$

Where:

PR = average Reservoir pressure, psi,

q = liquid rate, STB/d

PI = productivity index, STB/d/psi.

- If well inflow follows the Vogel model then Pwf is found from :

$$\frac{\mathrm{q}}{\mathrm{q_{max}}} = 1 - 0.2\,\frac{\mathrm{Pwf}}{\mathrm{PR}} - 0.8\left(\frac{\mathrm{Pwf}}{\mathrm{PR}}\right)^2 \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3-2$$

In order to calculate Composite Specific Gravity (γ_{comp}) we need to calculate specific gravity of water and for oil in composition

$$\gamma_{\text{water in composition}} = f_w * \gamma_w$$

$$\gamma_{\text{oil in composition}} = (1 - f_w) * \gamma_o$$

$$\gamma_{\text{comp}} = \gamma_{\text{water in composition}} + \gamma_{\text{oil in composition}}$$

Based on the flowing bottomhole pressure (Pwf) at the perforations the pressure at the pump's suction (pump intake pressure, PIP) is found from the following formula, using the fluid gradient valid in the annulus below the pump setting depth:

$$\text{PIP} = \text{Pwfd} - \left[(\text{Datum Depth} - \text{Pump Depth}) \times \gamma_{\text{comp}}/2.31\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots 3-3$$

3.4.2.2. **Gas Calculations**:

Equipment selection and design can be much more complicated in the case of presence of excessive amount of gas. From intake to discharge, volume, density and pressure values are changing in the liquid and gas mixture. Presence of gas at the discharge of the tubing can result a reduction in the required discharge pressure. Separation of the liquid and gas phase in the pump stages and slippage between phases can cause lower pump head than the required value. A submergence pressure below the bubble point to keep the gas all in liquid phase is the ideal case, in the reverse condition free gas volume must be separated from the other fluids by the help of gas separators. Depending on the amount of gas and well conditions combinations of equipments are available. Some equipments use the natural buoyancy of the fluids for separation while some can use the fluid velocity to produce a rotational flow for inducing radial separation of gas.

To decide which kind should be used it is necessary to determine the gas effect on fluid. If solution gas/oil ratio (RS, scf/stb), the gas volume factor (Bg, bbl/Mcf) and the formation volume factor (Bo, rbbl/stb) are not available from the well data they should be calculated. Those ratios were used for calculating the amount of water oil and free gas in the solution, and their effect on the fluid characteristics.

- Determining RS with Standing's Equation

$$R_s = \gamma_g \times \left[\left(\left({P_b}/{18}\right) \times \left({10^{0.0125\times API}}/{10^{0.00091\times T}}\right)\right) \times \gamma_{comp}/2.31\right]^{1.2048} \quad \ldots\ldots\ldots.3-4$$

- Determining B_o with Standing's Equation

$$Bo = 0.972 + 0.000147 \times F^{1.175} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots..\ldots\ldots\ldots 3-5$$

$$F = Rs \times \left[\frac{\gamma_g}{\gamma_o}\right]^{0.5} + 1.25 \times T \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots.\ldots\ldots\ldots\ldots\ldots..\ldots\ldots\ldots 3-6$$

- Determining B_g

$$B_g = 5.04 \times z \times {T}/{PIP} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots...\ldots\ldots\ldots\ldots\ldots..\ldots\ldots\ldots 3-7$$

Where;

z = Gas compressibility factor

Rs= solution gas/oil ratio, scf/STB

T =suction temperature, F

γ_g= gas specific gravity and γ_g= oil specific gravity

With the help of Rs, B_o and B_g, Total volume of fluids entering to the pump and percentage of free gas at the pump intake can be calculated.

Total Volume of gas = TG = BOPD * GOR /1000

Solution gas = SG = BOPD * Rs /1000

Free gas = FG = TG – SG

Volume of oil at pump intake = V_O = BOPD * Bo

Volume of free gas at pump intake= V_g = FG * Bg

Volume of water at pump intake = V_W = Q * WC%

The total volume of fluid at pump intake: VT = V_O + V_W + V_g

Free gas percentage = V_g / VT * 100

As the percentage of gas at pump intake Less than 10% by volume it is expected that

Pump performance will not be affected by gas, so no need for gas separator

3.4.2.3. Total Dynamic Head Calculations:

In the design procedure another important step is the calculation of total dynamic head (TDH, ft). For applications pumping a single phase fluid, the term Total Dynamic Head can be used to summarize the differential pressure or head the pump must supply to lift fluid at a desired flow rate from an operating fluid level in the well to the surface. It consists of the following components, **[12]**:

- The Net Vertical Lift or net distance which the fluid must be lifted
- The friction loss in the tubing string
- The wellhead pressure which the unit must pump against.

Now, the TDH is calculated in head (ft) units as follows:

$$\mathrm{TDH} = \frac{2.31}{\gamma_l} \times (\mathrm{WHP} - \mathrm{CHP}) + \mathrm{L_{dyn}} + \Delta\mathrm{H_{fr}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3-8$$

Where:

WHP = wellhead pressure, psi

CHP =casing head pressure, psi

L_{dyn}= TVD of the dynamic liquid level, ft

DHfr= frictional head loss in the tubing string, ft

γ_L = specific gravity of the produced liquid.

3.4.2.4. Selection of the Pump, [2]:

The selection of the proper ESP pump for operating in a given well involves:

- The determination of the pump series (outside diameter) to be used,
- The selection of the required pump type,
- The calculation of the required number of stages, as well as
- The checking of the mechanical strength of the selected pump.

- **Pump series:**

The most important selection criteria are that the chosen pump should fit in the casing string of the well. Centrifugal pumps are manufactured in different outside diameters; their series numbers usually represent their outside diameters. When selecting the pump series to be used, economic considerations command the choice of pumps with the largest OD that can be run in the given casing size. This is because ESP components (pumps, motors, etc.) with identical technical parameters but different ODs, due to manufacturing complications, are less expensive if they have a larger OD.

- **Pump Type:**

Pump types differ in the design of the stages such as the shape and number of vanes, the height, angle and length of vanes, and so on. All these factors have an impact on the liquid flow rate and the head developed by a pump stage. Pump type selection is based on the comparison of the well's desired liquid production rate and the recommended liquid capacity ranges of the pump types available. The ESP pump type selected should:

- Have the required liquid rate within its optimum capacity range, and
- Have the rate belonging to its best efficiency point (BEP) to fall close to the desired rate.

- **Number of Stages**:

The individual stages in a multistage centrifugal pump develop identical heads which are additive, so a pump with a given number of stages develops a total head equal to the sum of the heads of all stages. This allows the determination of the necessary number of stages for a given case where the total head represented by the TDH is known. In order to determine the required number of stages, one has to read the head developed by one stage at the desired liquid production rate and use the following formula:

$$\mathrm{Stages} = \frac{\mathrm{TDH}}{\mathrm{head}/\mathrm{stage}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 3-9$$

Where:

Head/stage = head developed by one stage of the selected pump, ft.

3.4.2.5. **Selection of the Protector**:

The protector or seal section of the ESP unit performs several vital functions for the proper operation of the installation, the most important of them being absorbing the axial thrust developed in the pump. This is the reason why protectors are selected primarily on the basis of the calculated thrust load developed by the pump. In addition to thrust load capacity, several other features have to be considered when selecting the proper protector for a particular application:

•The right size (series) is to be chosen,

•The protector shaft should be capable to transfer the required power,

•The protector's oil expansion capacity should be sufficient.

The available sizes of protectors are compatible with motor and pump series and the proper outside diameter is selected to match the ODs of the selected motor and the pump.

3.4.2.6. **Motor Selection:**

The procedure of Motor selection involves:

- The proper motor series (outside diameter),
- The required motor power, and
- The right combination of motor voltage and amperage.

The motor series with the largest OD that can be run in the well casing should be preferred. Often, motors with outside diameters different from the ESP pump are used, mainly because larger diameter motors are less expensive. Since electric power is defined as the product of voltage and amperage, motors with higher voltage values require less current, and vice versa. This feature gives the designer a great flexibility to achieve an optimum selection of motors for various conditions with the objective of maximizing the economy of fluid lifting.

In most situations the motor with the highest voltage requirement is the proper choice. This not only reduces the total power consumption but often allows the use of a smaller and less expensive power cable.

3.4.2.7. **Power Cable Selection:**

The electric power cable is a vital part of the ESP system and its proper selection is not only a technical task but requires, as it will be shown later, economic considerations as well. Cable for the ESP industry is manufactured in a wide variety of types, sizes, etc. When designing an ESP installation the right cable is selected by determining its required

- length,
- Type
- Size With proper considerations of all operational conditions.

- **Cable Length**:

The length of the power cable is determined from the running depth of the motor to which a sufficient length needed for the safe connection of surface equipment (about 100 ft) is added.

- **Cable Type**:

ESP cables are manufactured in a wide variety of types, i.e. with different insulating and conductor materials, constructions and armors. The proper choice primarily depends on:

- The material of choice for cable conductors is copper, especially in deeper wells, since aluminum has a lower conductivity.
- The two most common materials used for the insulation of the individual conductors are polypropylene and EPDM (ethylene propylene diene monomer), their temperature limits are 205 F and 400 F, respectively. Polypropylene is susceptible to degradation by light hydrocarbons, CO_2 and hydrocarbon gases. EPDM materials have a much wider temperature range and are less sensitive to gases.
- Jackets are made from Nitril or EPDM materials, the latter being used at higher temperatures.
- Braids or tapes provide additional strength and protection to cable Components.
- Metal armor provides mechanical protection to the cable during running and pulling and the choices are galvanized or stainless steel and Monel.

- **Cable Size:**

The main considerations for selecting the size of the power cable are: (a) the physical dimensions and (b) the voltage drop along the cable.

The voltage drop occurring in the cable is a function of the conductor size and the motor current, and is a direct indicator of the energy losses occurring along the cable. If the effect of conductor size on the operation of the whole ESP system is investigated, it is easy to see that smaller conductors mean greater energy losses and proportionally greater operational costs. But, at the same time, cable investment cost is lower than for a bigger conductor size. Bigger cable sizes, on the other hand, result in lower operating expenses but higher investment costs. Therefore, the selection of the optimum cable size should involve not only technical but economic considerations as well.

3.5. Limitations and considerations, [12]:

3.5.1. Motor OD vs. Casing ID

Generally speaking, the motor outside diameter is limited by the casing I.D. or in some cases by the pump type selected. In other cases, consideration has to be made for well deviation radii (dogleg severity) when running the motor to the desired location, but this also entails consideration of the length of motor as well. In the case of deviated wells, a check should be made that the motor selected is capable of moving around the bend when being installed. The motor OD/casing ID ratio can help in establishing the required fluid rate around the motor. It is recommended to use a minimum fluid velocity of 1 ft/s to get proper motor cooling but a maximum value of 12 ft/s (in an abrasive environment, 7 ft/s) to prevent housing erosion. Consideration should be given to gassy or poorly conductive fluids.

Having decided on the diameter of motor required, it is very unlikely that the horsepower required will match a horsepower listed in the manufacturer's catalog for the motor diameter selected. A decision has to be made whether to select a motor rated for a horsepower higher or lower than the horsepower required.

3.5.2. Well Temperature vs. Motor Cooling

Most submersible motor manufacturers list a bottom hole temperature (BHT) in which their motor can operate. The user should be very careful with this number. The BHT only defines the ambient or motor environmental temperature in which the motor operates. Probably the most important factor is the actual motor operating temperature or its internal temperature when the motor is operating. In other words, the temperature rise of the motor during load conditions plus the ambient temperature gives the operating temperature. Excessive motor operating temperatures can shorten motor insulation life, shorten the bearing life and result in mechanical problems from thermal expansion of components.

Normally, the manufacturer knows what the motor temperature rise will be from tests done in a controlled environment at the factory. In most cases, this controlled environment will have little resemblance to the real well conditions.

Some of the conditions that will affect the operating temperature of the motor in the well are: horsepower required, bottom hole temperature (flowing and static), water cut, Oil API gravity, rate of fluid flow by the motor, amount of gas flow by the motor, whether a variable speed drive is used (and at what frequency), presence of scale, existence of special motor housing coatings, voltage unbalance and the motor efficiency at the operating load point.

3.5.3. Seal Section Temperature Rating vs. Well Temperature

Operating temperature of the seal section is an important consideration; There are several factors that affect the actual operating temperature of the seal chamber section: bottom hole temperature, actual motor temperature rise, heat transfer properties of the well fluid, speed of the well fluid as it passes the seal chamber section, and temperature rise of the well fluid as it passes the motor. Operation temperature of the seal chamber section (except the thrust bearing) is typically 25°F – 50°F greater than the well temperature. Operating temperature should also be considered when selecting the type of oil to be used in the seal chamber. In general, oil viscosity decreases as temperature increases. At operating temperature, the oil viscosity must be sufficient to provide lubrication for the seal chamber section bearings. Selection of oil types used to accommodate a range of operating temperatures should be based on the ESP manufacturer's recommendations to ensure proper bearing operation. Generally, ESP manufacturers specify the elastomer formulation used in various components and offer several choices for varying well conditions.

Typical maximum service temperatures for several elastomers are shown below:

Nitrile: 250°F (121°C)

Highly Saturated Nitrile (HSN): 275°F (135°C)

Fluoroelastomer compounds: 325°F (163°C)

Tetrafluoroethylene/propylene copolymer (TFE/P): 350°F (177°C)

3.5.4. Thrust Bearing Load Rating vs. Thrust Developed

The thrust load rating for the seal chamber section should be greater than the highest possible thrust load for the application. Bearing surfaces are made from a wide range of materials. Babbitt is commonly used and is rated for operating temperatures up to 300°F (149°C). Bronze alloys may be used for high temperature applications (greater than 250°F). A number of plastic formulations have been developed for use in thrust bearings and are rated for high loads and high temperatures. The capacity of a thrust bearing may be reduced at elevated temperatures or by rotating opposite to the design direction

3.5.5. Well Temperature vs. Conductor Temperature

Conductor temperature is the temperature on the surface of the current carrying conductors. Cable operating temperature is a function of the well temperature and the conductor temperature. Cable operating temperatures can exceed bottom hole temperature by more than 30°F. When selecting cable, the conductor temperature or cable operating temperature should not be above the manufacturer's established temperature rating of the cable.

3.5.6. Cable Size vs. Voltage Loss

The smaller the conductor size, the greater the voltage drop per unit length and the more electrical power is lost to heat rise in the cable. These power losses can increase operational costs significantly, especially if cost per kilowatt is high. If voltage drop is excessive, the motor may not start. These concerns must be balanced against the increased initial cost of larger conductor sizes and whether there is room within the drift diameter of the casing for the larger cable.

CHAPTER 4

Nodal Analysis Approach

4.1. Introduction:

Petroleum fluids **[2],** found in an underground reservoir move through a complex system to reach their destinations on the surface. This system is called the "production system" and comprises the following main components: the reservoir, the producing well, the surface flowline and the separator. Some of these can be further divided into smaller elements; for example, the well, besides the tubing string, may contain safety and/or gas lift valves, as well as other components. The production system is thus a system of interconnected and interacting elements that all have their own specific performance relationships, but each, in turn, also depends upon and influences the other elements. In order to produce fluids from the well, all components of the system must work together. Thus, the solution of any fluid production problem requires that the production system be treated as a complete entity.

Nodal analysis **[13] [14] [15]**, defined as a system approach to the optimization of oil and gas wells, is used to evaluate thoroughly a complete producing system. Every component in a producing well or all wells in a producing system can be optimized to achieve the objective flow rate most economically. All present components beginning with the static reservoir pressure, ending with the separator, and including inflow performance, as well as flow across the completion, up the tubing string including any (downhole restrictions and safety valves) , across the surface chock (if applicable), through horizontal flow lines, and into the separation facilities-are analyzed. The main objectives of the Nodal analysis are as follows.

1. To determine the flow rate at which an existing oil or gas well will produce considering well bore geometry and completion limitations (first by natural)
2. To determine under what conditions a well will load or die.
3. To select the most economical time for the installation of artificial lift and to assist in selection of the optimum lift method.
4. To optimize the system to produce the objective flow rate most economically.

5. To check each components in the well system to determine whether it is restricting the flow rate unnecessarily
6. To permit quick recognition by the operator's management and engineering staff of ways to increase production rates.

Nodal analysis technique, is considered also as an essentially a simulator of the producing well system. The system includes all flow between the reservoir and the separator. As the entire system is simulated, each of the components is modeled using various correlations or equations to determine the pressure loss through that component as a function of flow rate. The summation of these individual losses make up the total pressure loss through the entire system for a given flow rate.

4.2 Application of Nodal Analysis Approach to ESP System

NODAL analysis can be professionally applied to wells produced by ESP pumps. **Figure (4-1)** illustrates the appropriate node points for ESP installation system.

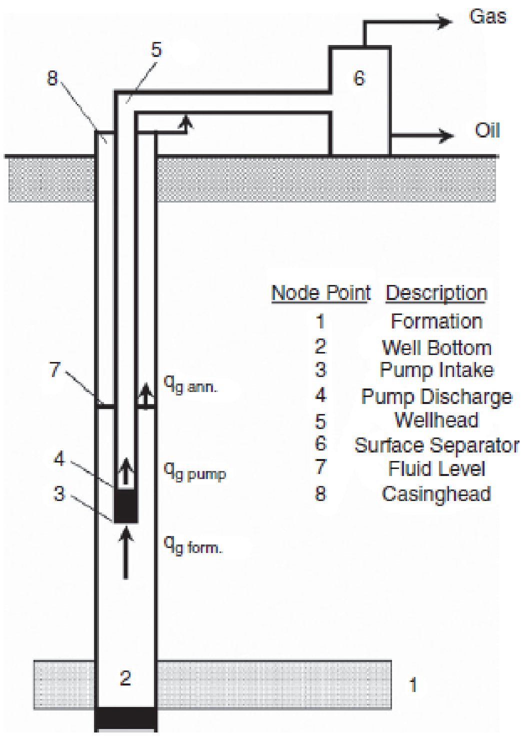

Figure (4-1) the production system of an oil well produced by an ESP pump **[2]**.

The application of systems analysis principles permits the calculation of the liquid rate occurring in the production system. In general, the nodal analysis procedure consists of the following basic steps:

- Solution Node is selected first. This can be any node point in the system, the proper selection of which facilitates the evaluation of different assumed conditions.
- A range of liquid flow rates is selected for subsequent calculations.
- Starting from the two endpoints of the system (Node 1 and Node 6) and working toward the Solution Node, the flowing pressures at every node point are calculated for the first assumed liquid rate.
- After repeating the calculations in Step 3 for each and every assumed liquid flow rate, two sets of pressure/rate values will be available at the Solution Node. These values represent the performance curves for the two subsystems created by the Solution Node.
- According to a basic rule of systems analysis, inflowing and outflowing pressures at the Solution Node must be equal. Thus the intersection of the two performance curves defines the well's liquid flow rate under the given conditions **[2]**:
  The inflow and outflow expressions are as following:

Inflow: $$\mathrm{P_R} - \Delta\mathrm{P_{res}} - \Delta\mathrm{P_{CSg}}(\text{below Pump}) = \mathrm{P_{up}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots..4-1$$

Outflow: $$\mathrm{P_{sep}} + \Delta\mathrm{P_{flowline}} + \Delta\mathrm{P_{tug}}(\text{above Pump}) = \mathrm{P_{dn}} \ldots\ldots\ldots\ldots...4-2$$

Where:

P_R= Reservoir pressure

P_{up}= Pump intake pressure

P_{dn}=Pump discharge pressure

P_{sep}= Separator pressure

The following procedure may be used to estimate the pressure gain and power required to achieve a particular producing capacity.

Inflow:

- Select a value for liquid producing rate q_L.
- Determine the required P_{wf} for this q_L .using the reservoir performance procedures.
- Determine the pump suction pressure Pup using the casing diameter and the total Producing GLR to calculate the pressure drop below the pump
- Repeat for a range of liquid producing rates and plot P_{up} versus. q_L .

Outflow:

1. Select a value for q_L.
2. Determine the appropriate GLR for tubing and flow line pressure drop calculations.
   - Determine P_{up} and fluid temperature at the pump at this q_L value from inflow calculations.
   - Determine dissolved gas Rs at this pressure and temperature.
   - Estimate fraction of free gas E_s, separated at the pump. This will be dependent whether or not a downhole separator is to be used. If not use E_s= 0.5
   - Calculate the GLR downstream of the pump from

$$\mathrm{GLR_{dn}} = (1 - \mathrm{Es}) \times (\mathrm{R_{total}} - \mathrm{Rs} \times \mathrm{f_o}) \ldots\ldots\ldots\ldots 4-3$$

Where:

R_{total} = Total producing gas/liquid ratio,

R_s = Solution gas/oil ratio at suction conditions, and

f_o = Fraction of oil flowing

3. Determine P_{dn} using GLR_{dn} to calculate the pressure drop in the tubing and the flowline if the casing gas is vented. If the casing tied into the flow line, the total GLR will be used to determine the pressure drop in the flow line.
4. Repeat for a range of q_L and plot P_{dn} vs. q_L on the same graph.
5. Select various producing rates and determine the pressure gain Δp required to achieve an intersection of the inflow and outflow curves at these rates. The suction and discharge pressures can also be determined for each rate.

6. Calculate the power requirement, pump size, number of stages ….etc at each producing rate.
   - The required horsepower can be calculated from:

$$\mathrm{HP} = 1.72 \times 10^{-5} \times \Delta\mathrm{P} \times (\mathrm{q_o B_o} + \mathrm{q_w B_w}) \ldots\ldots\ldots\ldots 4-4$$

Where:

HP = Horsepower required

Δ_p = Pressure gain, psi

q_o = Oil rate, STB/day

q_w = Water rate, STB/day

B_o = Oil formation volume factor at suction conditions, bbl/STB, and

B_w = water formation volume factor at suction conditions

The pressure gain can be converted to head gain if necessary for pump selection. This is accomplished by dividing the pressure gain by the density of the fluid being pumped. The actual plotting of the data is not required if the pump is to be selected for specific rates, as all the necessary information is calculated before plotting **[14]**.

CHAPTER 5

Electrical Submersible Pumps Optimization of the X Field in Libya

5.1 Introduction

The first step to optimize the available 6 ESP lifted oil wells in the field was to review the data sets available to help in understanding the pump operating behavior. The diagnosis based on all such concepts enables right / real time decision to sustain ESP at optimum range, leading to enhancing ESP run life.

The well design, well inflow and outflow behavior analyzed simultaneously (the intersection point of both of these curves precisely defines the well operating point) to evaluate the current performance of the pumps used in conjunction with the operating conditions. All ESP components are selected according to API Recommended practice 11S4 and 11S2.

Nodal analysis techniques are recommended as the best process for defining well performance and considering sensitivity to changes over time or due to variations in available data. These techniques are used both numerically and graphically to provide a good understanding of the for a number of varying conditions that could become visible during wells life.

5.2 Software used Overview, [18].

PROSPER is a fundamental element in the Integrated Production Model as defined by Petroleum Experts. It is a well performance, design and optimization program for modeling most types of well configurations found in the worldwide oil and gas industry today

PROSPER is designed to allow building of reliable and consistent well models, with the ability to address each aspect of well bore modeling; PVT (fluid characterization), VLP correlations (for calculation of flow line and tubing pressure loss) and IPR (reservoir inflow). By modeling each component of the producing well system, the User can verify each model subsystem by performance matching. Once a well system model has been tuned to real field data, **PROSPER** can be confidently used to model the well in different scenarios and to make forward predictions of reservoir pressure based on surface production data.

PROSPER provides unique matching features which tune PVT, multiphase flow correlations and IPR to match measured field data, allowing a consistent model to be built prior to use in prediction (sensitivities or artificial lift design). The **s**ensitivity calculation features enable existing well designs to be optimized and the effects of future changes in system parameters to be assessed **[19]**.

5.3 Input Data Required

To design ESPs by PROSPER the following input data are obligatory:

1. **PVT Lab Data**

   To predict pressure and temperature changes from the reservoir, along the well bore and flow line tubular, it is necessary to accurately predict fluid properties as a function of pressure and temperature. So, a fully accurate PVT data is important:

- Solution Gas Oil Ratio
- Oil Gravity
- Gas Gravity
- Water Salinity
- Impurities (CO2,N2, H2S)
- Bubble Point Pressure

Further PVT Lab Data in tubular, Pressure, Gas Oil Ratio, oil Formation Volume Factor and oil viscosity.

2. **Well Test Data**

- Well head Flowing Pressure

- Flowing Tubing Head Temperature
- Water Cut
- Liquid Rate
- Measured Gauge Depth
- Measured Gauge pressure
- Static Reservoir Pressure at Top of Perforation
- Produced Gas Oil Ratio

3. Down hole Equipment Data

- Tubing Outer Diameter
- Tubing Inside Diameter
- Casing Internal Diameter

4. ESP design Parameters

- Pump Depth
- Operating Frequency
- Maximum Pump Outer Diameter
- Length of Cable
- Design Liquid Rate

5.4. Major Design Procedures

1. In the PVT section, where both basic fluid properties data and some PVT laboratory measurements are available, modify the standard black oil correlations to best- fit the measured.

2. In the next step, downhole equipment has to be entered where the Tubing string can be modeled using the following elements, Restriction, Tubing and Casing. The downhole equipment details should be entered down to the producing interval being analyzed.

3. Depending on the bubble point pressure, Choose the best flow model to describe the Inflow performance curve, in this study, PI Entry or a straight-line inflow model is used as the pressure is above the bobble point pressure for all studied wells. Following the equation:

$$\mathrm{PI} = \frac{q}{(P_R - P_{wf})} \qquad 5-1$$

   Where:

   PI = Productivity Index, STB/Day/Psi

   Q= flow Rate, STB/Day

   PR = Reservoir Pressure, Psi

   Pwf =Bottom hole pressure, Psi

4. In this study, the procedures divided into two main scenarios:

   4.1. **First scenario: analysis and optimization of existing ESP installation**

      1. Enter the input data as requested.
      2. Re-design current ESP pump to produce the current production rate trying to reduce the number of stages and increase pump efficiency as possible as it could be.

   4.2. **Second scenario: analysis and optimization of new ESP installation**

      1. Enter the input data as requested.
      2. Design a new ESP pump to produce high production rate and take into account increasing pump efficiency as possible as it could be.

5. Perform ESP Quick look through the pressure traverses plot where pressure gradient are calculated from top to bottom and vice-versa. If the assumptions regarding well and ESP conditions (e.g. Pump frequency, water cut, IPR…etc) are correct, the two calculated traverses will overlay.
6. The system plot , Vertical Lift Performance and Inflow Performance curve Relationship (VLP/IPR), for ESP-lifted wells are done considering that the solution node is placed at the top of ESP. this means that
    6.1. the VLP accounts for pressure drop from the wellhead to the top of ESP
    6.2. The IPR curve included the pressure drop across the reservoir.
    6.3. The pump intake pressure PIP includes the pressure drop across the reservoir plus the pressure drop in the well up to the pump inlet.
    6.4. The pump discharge pressure PDP includes the pressure drop across the reservoir plus the pressure drop in the well up to the well inlet and the pressure gain across the ESP.
    6.5. The solution rate is the intersection between the VLP and PDP.
7. Performing Sensitivity Analysis

5.5. Economic Evaluation

In order to make the best possible decisions that will enable us to meet specific objectives such as increase oil production, maximize recovery, minimize capital expenditures, and minimize operating costs and to optimize Profitability, it is essential matter to do an economic evaluation for the aimed cases by means of the most widely known profit indicators as following:

1. **Net present value** (**NPV**) of a time series of cash flows, both incoming and outgoing, is defined as the sum of the present values (PVs) of the individual cash flows. It is used to analyze the profitability of an investment or project

   Each cash inflow/outflow is discounted back to its present value (PV). Then they are summed. Therefore NPV is the sum of all terms,

$$\mathrm{NPV} = \sum_{t=1}^{n} \frac{NCF}{(1+i)^{(t-0.5)}}$$

Where:

t : the time of the cash flow

i : the discount rate

NCF: the net cash flow (the amount of cash, inflow minus outflow) at time t.

2. **Payout time period** for a project refers to the period of time required for the return on an investment to "repay" the sum of the original investment.

CHAPTER 6

Results and Discussion

6.1 Introduction

The calculation steps used for Electrical submersible pump design were introduced in Chapter 5, Section 4. These steps were applied for the 6 ESP lifted wells

6.2 Well (X-1) analysis

X-1 well was originally completed as a vertical producer in 1980, where ESP with Y-tool was resized in Mar-1992. Due to motor flat failure, ESP was replaced in Aug- 1993. In Juy-1998 pump plugged with scale and new ESP was run. Last ESP installed was in Dec-2007. The new ESP pump increases the gross production rate from 326 STB/d to 750 STB/d over its run life, **Table (6-1)** shows completion input data , **Table (6-2)** illustrates well production and PVT input data and **Table (6-3)** illustrates ESP design parameters that were used in PROSPER software.

Items	Setting Depth, ft	Weight, lb/ft	Size, OD, in	Grade
Casing	798	72	13 3/8	N-80
Casing	4270	23	7	J-55
Tubing	3678	9.3	3 1/2	N-80
Perforation Depths ,ft	3701-3708 , 3882-3885 ,3967-3976 , 4086-4100			

Table (6-1) shows completion input data

Reservoir Pressure, Psi	1400
Flowing Bottom Hole Pressure, Psi	966
Tubing Head Pressure , psi	150
Productivity Index ,bbl/day/psi	1.73
Bottom Hole Temperature ,F	144
Well Head Temperature , F	115
Water Cut ,%	60
Salinity, ppm	88,000
Solution Gas Oil Ratio , SCF/STB	183
Bubble Point Pressure , Psi	486
Oil Gravity, API	40.02
Water Specific Gravity	1.060
Gas Specific Gravity	0.855

Table (6-2) illustrates well production and PVT input data

Manufacturer	REDA
Series	400
Model	D725N
Design rate, STB/day	750
Number of stages	158
Pump Efficiency, %	56.287
Pump Setting Depth, ft	3562
Head Required	2051.8
Pump intake Pressure	507.33
Design Frequency, Hz	50
Motor Type	Reda 375_87_Std
Nameplate Power, HP	19.50
Selected Cable	#4 Aluminium

Table (6-3) illustrates ESP design parameters

By using a non-linear regression technique, the results shows that best correlation to fit the measured PVT data was **Lasater** correlation for Bubble point pressure , Solution Gas Oil Ratio and Formation volume factor whereas Beggs. et.al correlation was used for oil viscosity. Since the well is flowing above the bubble point pressure, the Inflow Performance Relationship curve (IPR) was chosen to be PI Entry, **Figure (6-1**) shows IPR

Plot for well X1 where the theoretical maximum flow that the well could deliver or Absolute Open Flow (AOF) value is 2014.8 STB/day

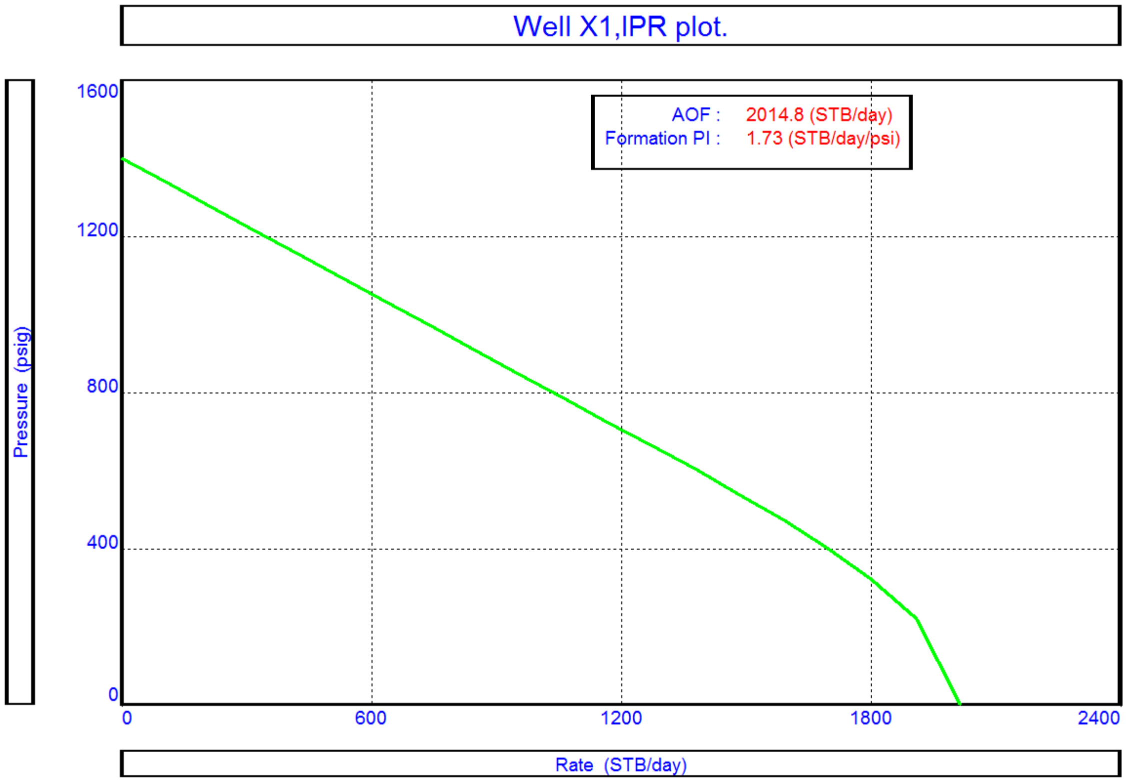

Figure (6-1) shows IPR Plot for well X1

- ***Case 1, analysis and optimization of existing ESP installation***

As it was mentioned in Chapter 2, the well is flowing at 750 STB/day by using REDA 400, D725N Pump with 158 stages. The re-optimization process in PROSPER showed that the current case could be improved by producing the same flow rate with less number of stages by changing the pump to be REDA 400, DN1100 .**Table (6-4)** shows the minimum ,maximum and the best efficiency point values for the pump at frequency 50 Hz .

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
500	917	1125

Table (6-4) shows the minimum, maximum and BEP values for DN1100 ESP pump@50 Hz

From the results, it is obvious that the new pump works inside the operating range as well pump efficiency is increased by almost 7.5% comparing to the current case. **Table (6-5)** shows Re- Design results for well X1 and **Figure (6-2)** shows new pump performance curve for well X1, Case 1.

Manufacturer	REDA
Series	400
Model	DN1100
Design rate, STB/day	750
Number of stages	110
Pump Efficiency, %	60.5212
Pump Setting Depth, ft	3562
Head Required	1909.51
Pump intake Pressure	684.703
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	22.5
Selected Cable	#4 Aluminium

Table (6-5) shows Re- Design results for well X1, Case 1.

By calculating pressure traverses plot as a Quick look from top to bottom and vice-versa as it is shown in **Figure (6-3),** the two curves were overlaying on each other indicating that assumptions regarding well and selected new pump are correct.

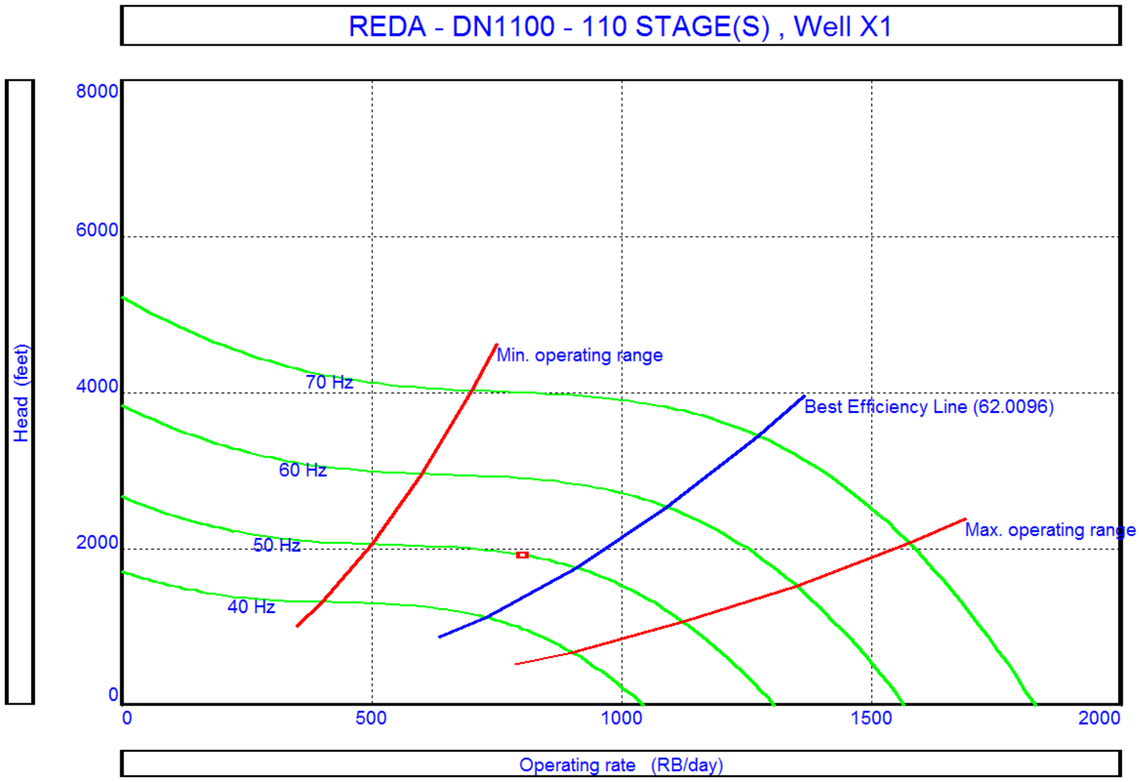

Figure (6-2) shows new pump performance curve for well X1, Case 1.

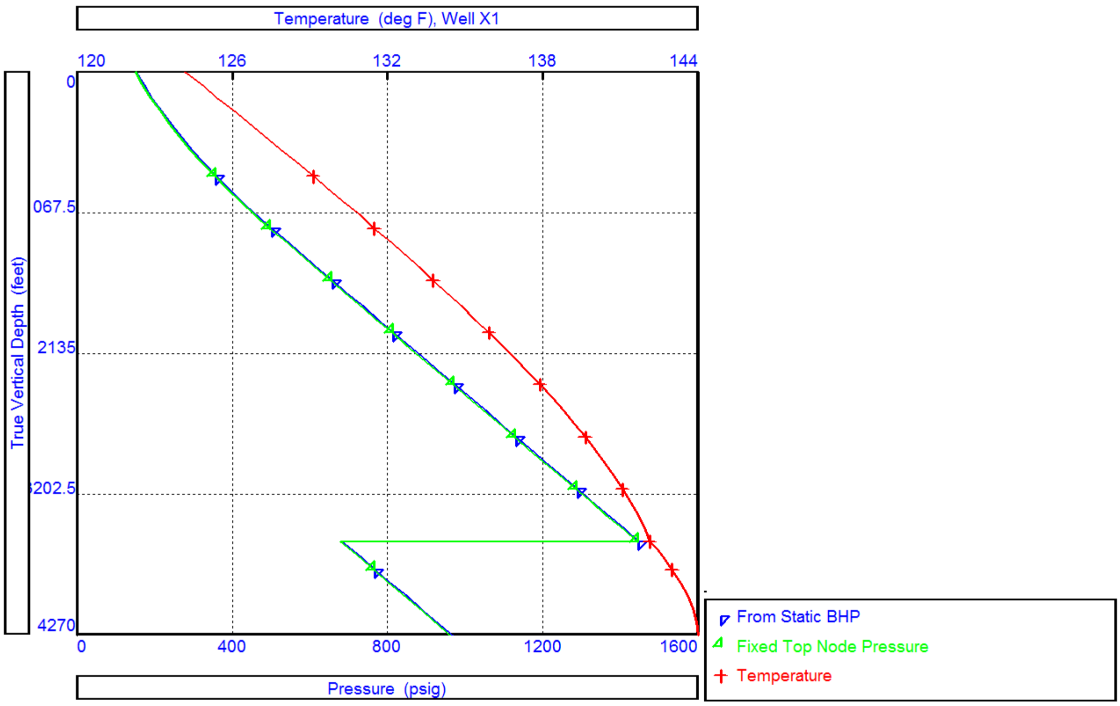

Figure (6-3) pressure traverses plot for well X1, Case 1.

- ***Case 2, analysis and optimization of new ESP installation***

In the second case, the designed production rate is increased by 33.33% considering the capability of the well and the new ESP equipment is designed including the pump, the motor and the cable. Raising the pump intake pressure to be above the bubble point pressure is one of the most important points which was taken into account to avoid gas forming and consequently using gas separator since it is costly. It is noticeable that the pump efficiency is increased by almost 10.1% comparing with the current case and the new pump –REDA 400, DN1300 works inside its operating range, **Table (6-6)**. The optimization results are shown in **Table (6-7)** and pump performance curve is shown in **Figure (6-4).**

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
800	1069	1367

Table (6-6) shows the minimum, maximum and BEP values for DN1300 ESP pump@50 Hz

Manufacturer	REDA
Series	400
Model	DN1300
Design rate, STB/day	1000
Number of stages	161
Pump Efficiency, %	61.9866
Pump Setting Depth, ft	3562
Head Required	2273.92
Pump intake Pressure	540.612
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	51
Selected Cable	#1 Copper

Table (6-7) shows new design results for well X1, Case 2.

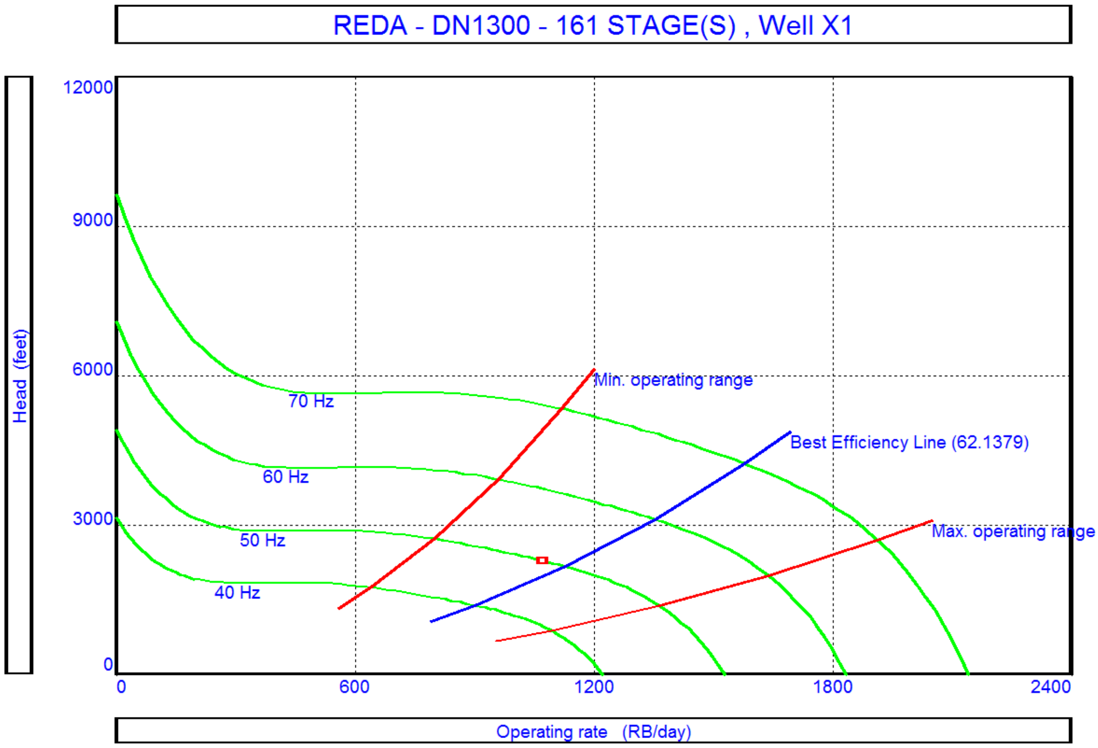

Figure (6-4) shows pump performance curve for well X1, Case 2.

The pressure traverses plot as a Quick look from top to bottom and vice-versa is shown in **Figure (6-5).**

As an assessment between the two cases, nodal analysis technique was applied that the solution node was taken at the pump outlet (pump discharge pressure not at the bottom of the well). Case 2 shows an enhancement in liquid production rate which is the intersection point between pump discharge pressure curve and the vertical lift performance curve. The liquid rate increment gets to 250 STB/d, **Figure (6-6).**

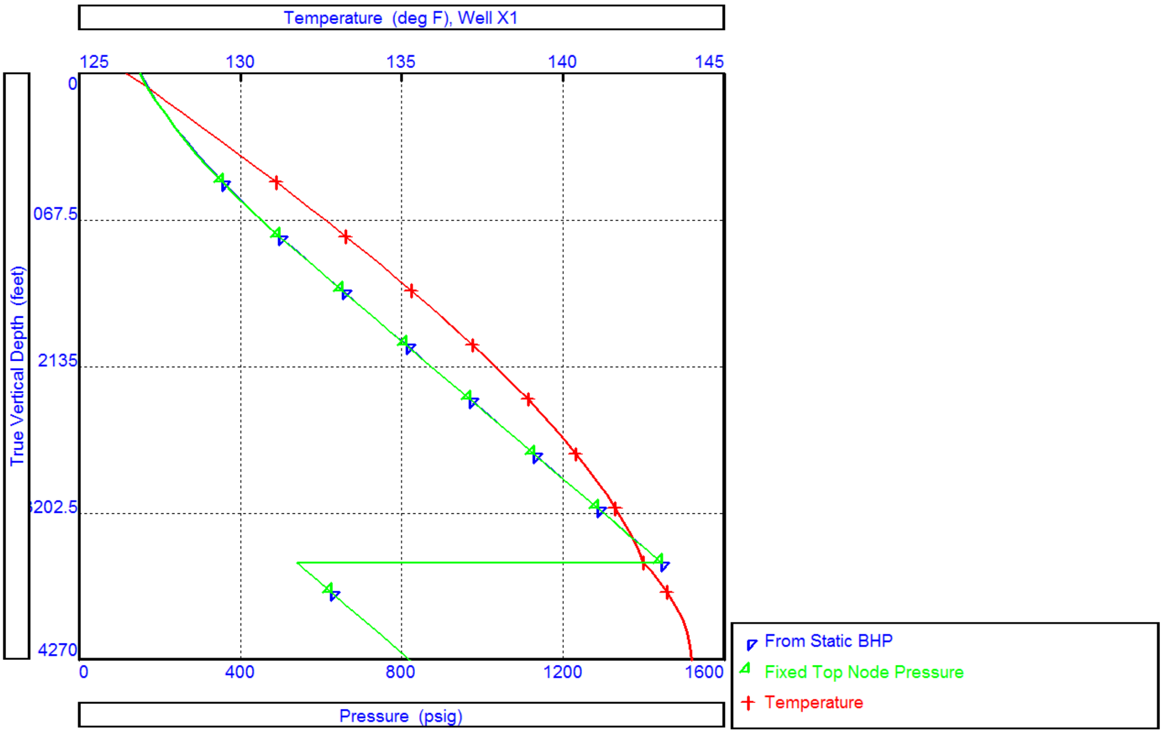

Figure (6-5) pressure traverses plot for well X1, Case 2.

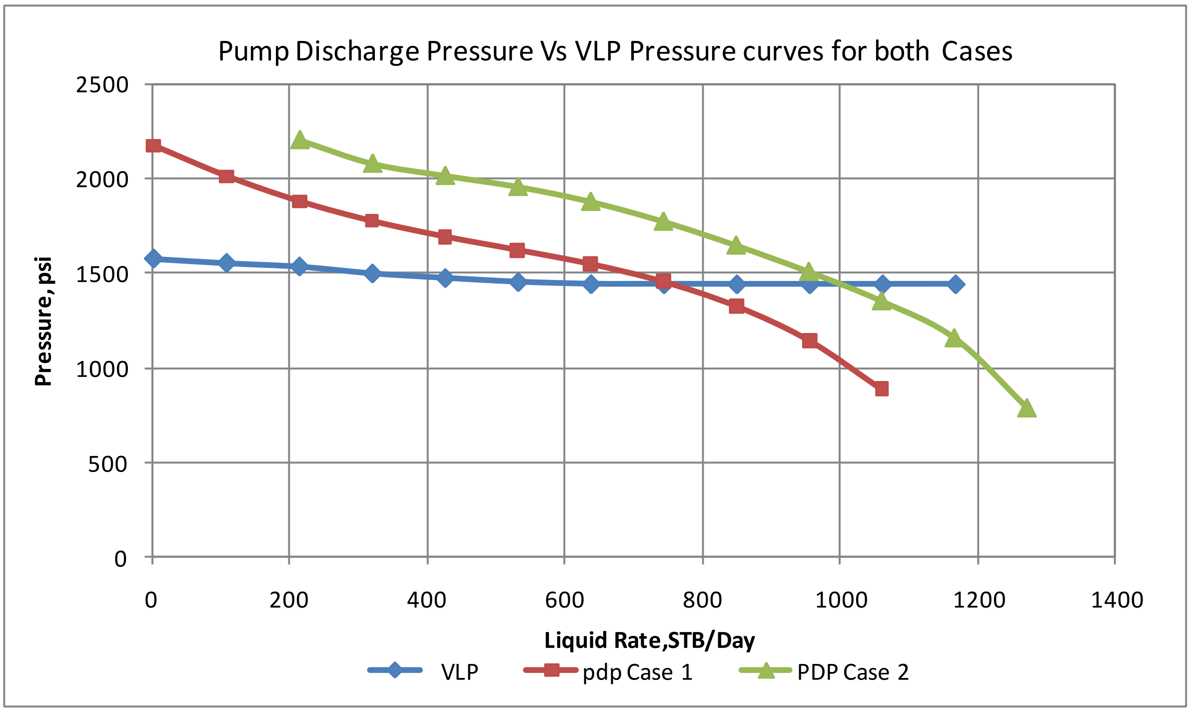

Figure (6-6) Pump discharge Pressure Vs Vertical Lift Performance plot for well X1.

6.3 Well (X-2) analysis

For X-2 well, Last ESP was installed in NOV-2007 and the last work over job was done because cable broken inside the connecter was checked. this changing helped to increase liquid flow rate from 428 STB/d to 882 STB/d. **Table (6-8)** shows completion input data, **Table (6-9)** illustrates well production and PVT input data and **Table (6-10)** illustrates ESP design parameters that were used in PROSPER software.

Items	Setting Depth, ft	Weight, lb/ft	Size, OD, in	Grade
Casing	42	94	20	H-40
Casing	851	68	13 3/8	J-55
Casing	4073	26	7	N-80
Tubing	3451	9.3	3 1/2	N-80
Perforation Depths ,ft	3509-3531 , 3683-3694, 3780-3788, 3901-3915			

Table (6-8) shows completion input data

Reservoir Pressure, Psi	1560
Flowing Bottom Hole Pressure, Psi	1200
Tubing Head Pressure , psi	190
Productivity Index ,bbl/day/psi	2.45
Bottom Hole Temperature ,F	144
Well Head Temperature , F	115
Water Cut ,%	60
Salinity, ppm	88,000
Solution Gas Oil Ratio , SCF/STB	183
Bubble Point Pressure , Psi	486
Oil Gravity, API	40.02
Water Specific Gravity	1.060
Gas Specific Gravity	0.855

Table (6-9) illustrates well production and PVT input data

Manufacturer	REDA
Series	400
Model	D725N
Design rate, STB/day	882
Number of stages	115
Pump Efficiency, %	53.420
Pump Setting Depth, ft	3293
Head Required	2217.2
Pump intake Pressure	618.117
Design Frequency, Hz	50
Motor Type	Reda 375_87_Std
Nameplate Power, HP	15
Selected Cable	#6 Copper

Table (6-10) illustrates ESP design parameters

The results shows that best correlation to fit the measured PVT data was **Lasater** correlation for Bubble point pressure , Solution Gas Oil Ratio and Formation volume factor whereas **Beggs. et.al** correlation was used for oil viscosity. **Figure (6-7**) shows IPR Plot for well X2 where the well is able to produce 3569.4 STB/day as a maximum production with a 2.45 STB/day/psi productivity index or PI.

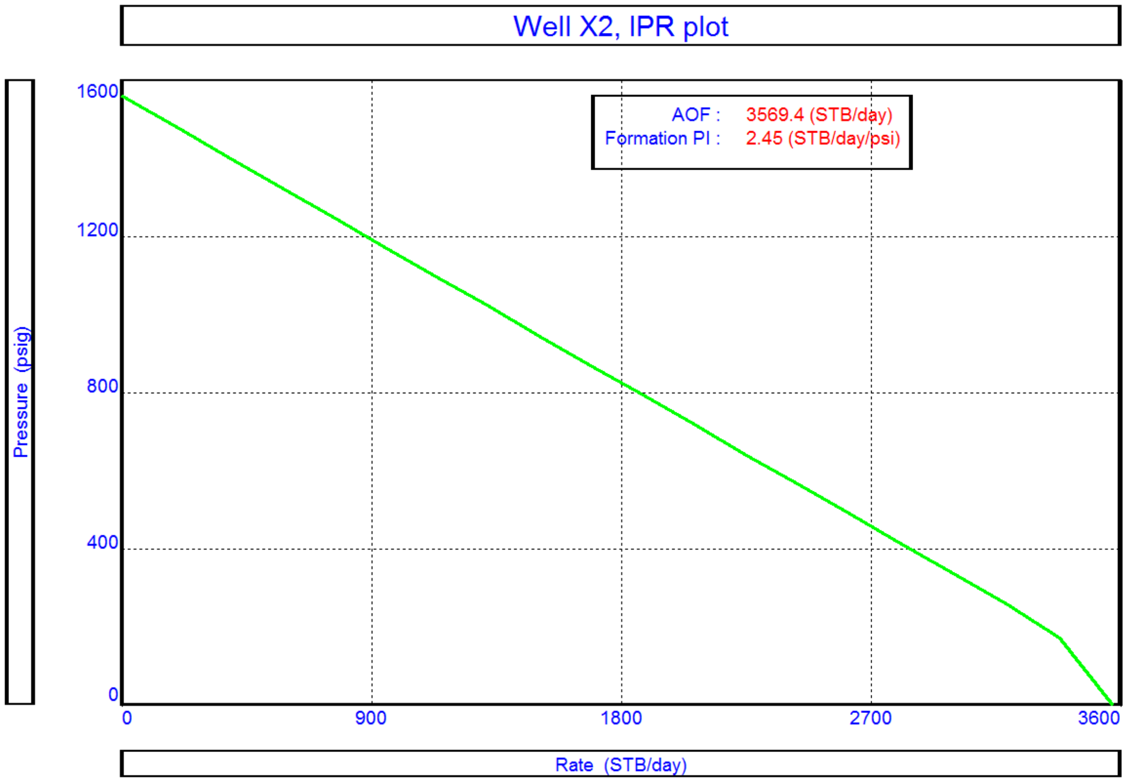

Figure (6-7) shows IPR Plot for well X2

- ***Case 1, analysis and optimization of existing ESP installation***

The well is flowing at 882 STB/day by using REDA 400, D725N Pump with 115 stages. The re-optimization process in PROSPER indicated that the this case could be improved with less number of stages by changing the pump to be REDA 400, DN1100 and 101 number of stages. **Table (6-11)** shows the minimum, maximum and the best efficiency point values for the pump at frequency 50 Hz.

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
500	917	1125

Table (6-11) shows the minimum, maximum and BEP values for DN1100 ESP pump@50 Hz

The results indicated that the new pump works inside its operating range as well pump efficiency is increased from 51.4% to be 61.98% comparing to the current case. **Table (6-**

12) shows Re- Design results for well X2 and **Figure (6-8)** shows new pump performance curve for well X2, Case 1.

Manufacturer	REDA
Series	400
Model	DN1100
Design rate, STB/day	882
Number of stages	101
Pump Efficiency, %	61.9878
Pump Setting Depth, ft	3293
Head Required	1588.94
Pump intake Pressure	883.926
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	22.5
Selected Cable	#6 Copper

Table (6-12) shows Re- Design results for well X2, Case 1.

As a quality check pressure traverses curves are plotted from top to bottom and vice-versa as it is shown in **Figure (6-9).**

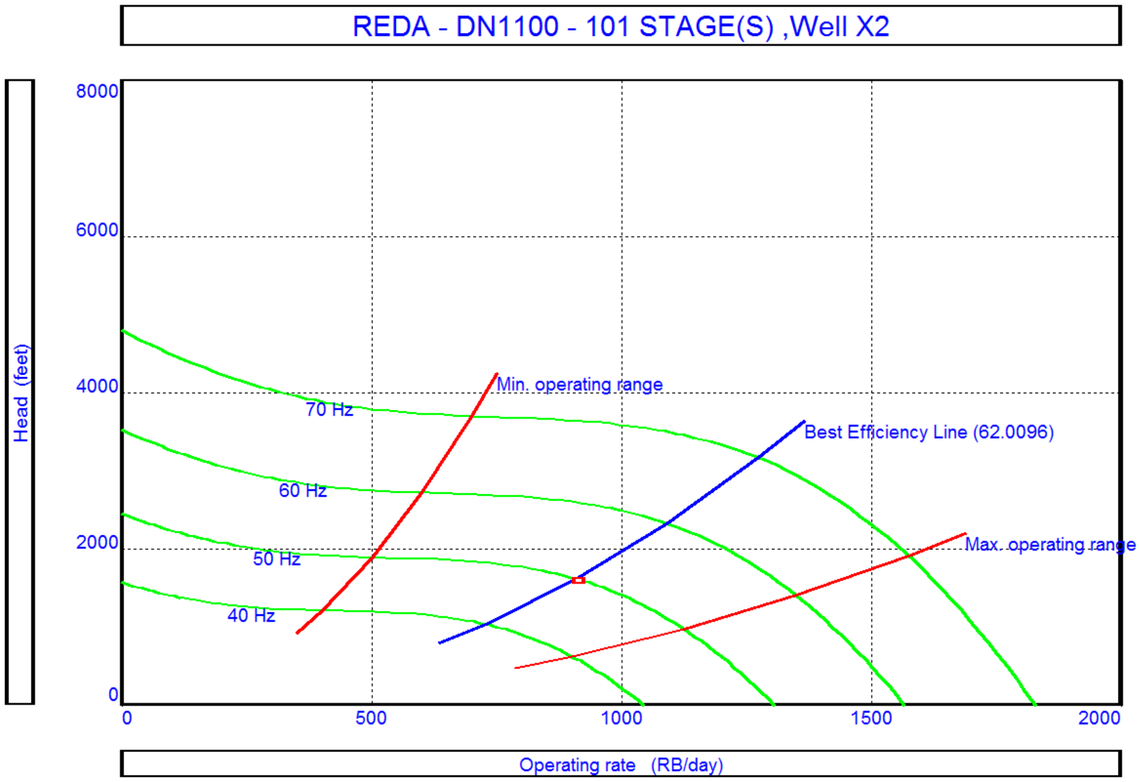

Figure (6-8) shows new pump performance curve for well X2, Case 1.

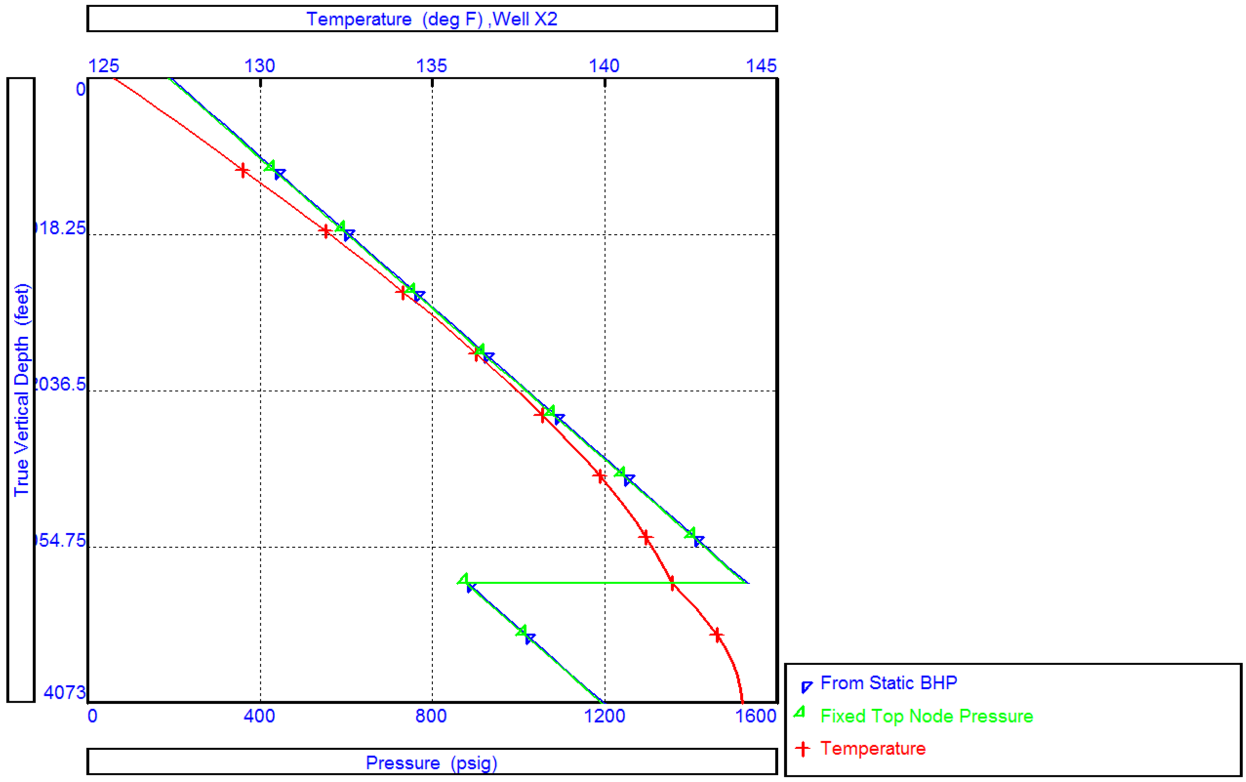

Figure (6-9) pressure traverses plot for well X2, Case 1.

- ***Case 2, analysis and optimization of new ESP installation***

To improve the production rate, a new larger pump is designed which helped to produce additional 618 STB/d with an increase in pump efficiency comparing to the current and first case to be 68.5 %. The new pump –REDA 400, DN1750 works inside its operating range, **Table (6-13)**. The optimization results are shown in **Table (6-14)** and pump performance curve is shown in **Figure (6-10).**

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
1000	1499	1708

Table (6-13) shows the minimum, maximum and BEP values for DN1750 ESP pump@50 Hz

Manufacturer	REDA
Series	400
Model	DN1750
Design rate, STB/day	1500
Number of stages	179
Pump Efficiency, %	68.4828
Pump Setting Depth, ft	3293
Head Required	2219.47
Pump intake Pressure	631.938
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	51
Selected Cable	#1 Copper

Table (6-14) shows new design results for well X2, Case 2.

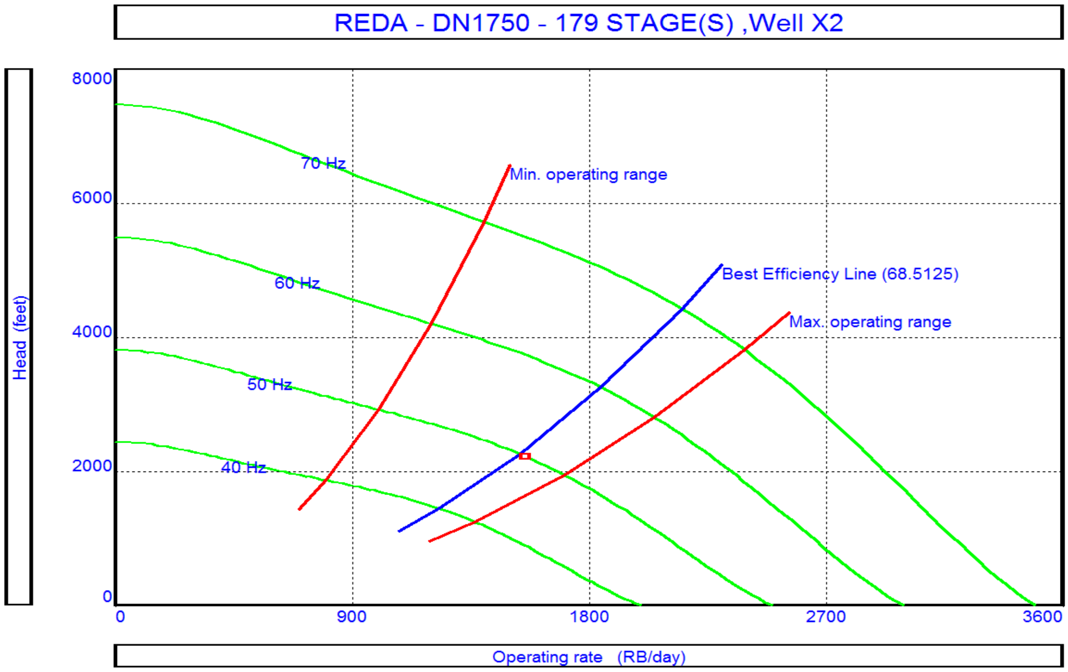

Figure (6-10) shows pump performance curve for well X2, Case 2.

The pressure traverses plot as a Quick look from top to bottom and vice-versa is shown in **Figure (6-11).**

Case 2 showed an enhancement in liquid production rate which is the intersection point between pump discharge pressure curve and the vertical lift performance curve. The liquid rate increment gets to 618 STB/d; **Figure (6-12).**

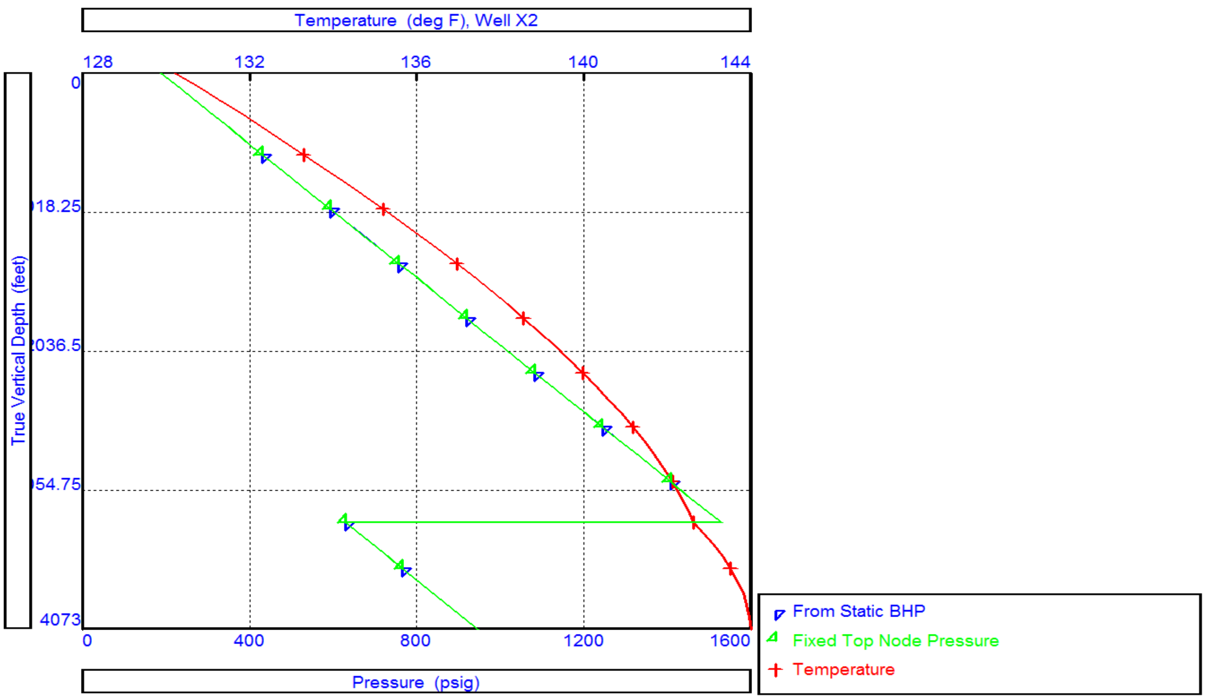

Figure (6-11) pressure traverses plot for well X2, Case 2.

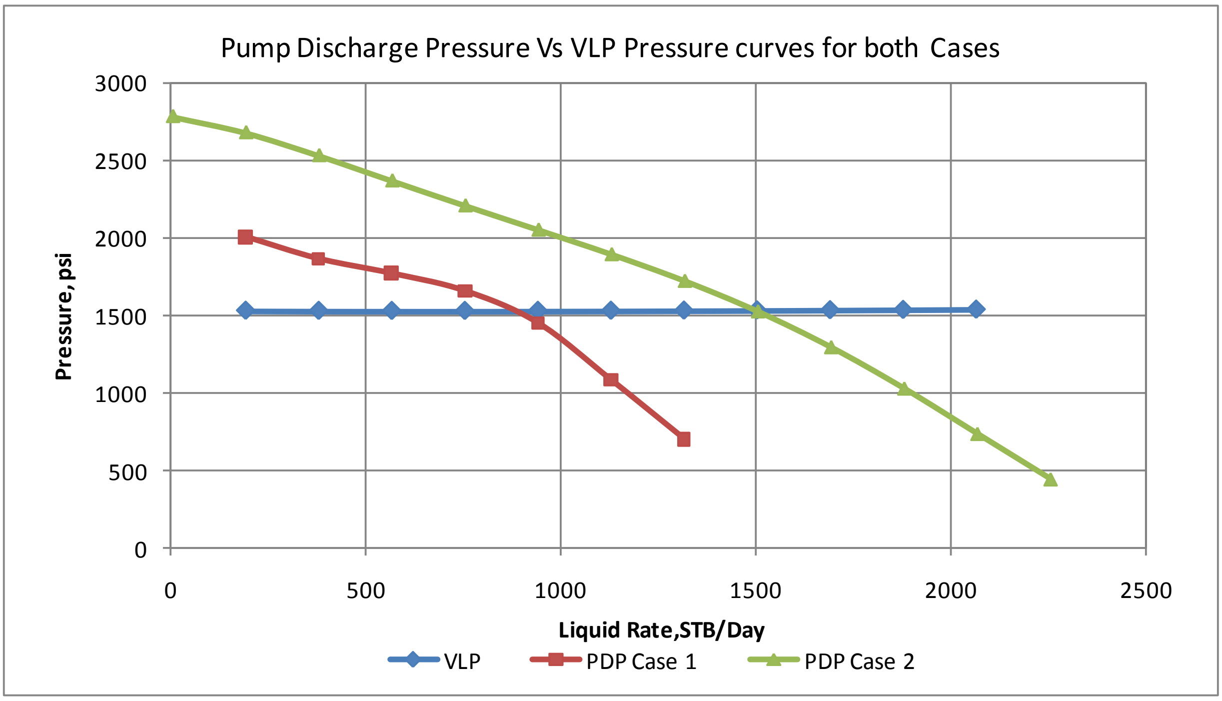

Figure (6-12) Pump discharge Pressure Vs Vertical Lift Performance plot for well X2.

6.4 Well (X-3) analysis

The initial completion for well X-3 was in 1980 and the first ESP installed in 1992 with Y-tool. The ESP replaced twice in 2004 due to frequently motor failure and the last one was installed on 2007 and this changing helped to increase gross flow rate from 281 STB/d to 500 STB/d.

Table (6-15) shows completion input data, **Table (6-16)** illustrates well production and PVT input data and **Table (6-17)** illustrates ESP design parameters that were used in PROSPER software.

Items	Setting Depth, ft	Weight, lb/ft	Size, OD, in	Grade
Casing	37	94	20	H-40
Casing	723	68	13 3/8	J-55
Casing	4059	26	7	J-55
Tubing	3454	9.3	3 1/2	N-80
Perforation Depths ,ft	3501-3899, 3972-3999			

Table (6-15) shows completion input data

Reservoir Pressure, Psi	1645
Flowing Bottom Hole Pressure, Psi	857
Tubing Head Pressure , psi	190
Productivity Index ,bbl/day/psi	0.635
Bottom Hole Temperature ,F	144
Well Head Temperature , F	115
Water Cut ,%	50
Salinity, ppm	88,000
Solution Gas Oil Ratio , SCF/STB	183
Bubble Point Pressure , Psi	486
Oil Gravity, API	40.02
Water Specific Gravity	1.060
Gas Specific Gravity	0.855

Table (6-16) illustrates well production and PVT input data

Manufacturer	REDA
Series	400
Model	DN675
Design rate, STB/day	500
Number of stages	159
Pump Efficiency, %	57.999
Pump Setting Depth, ft	3442
Head Required	2255.4
Pump intake Pressure	465.86
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	19.5
Selected Cable	#6 Copper

Table (6-17) illustrates ESP design parameters

The results showed that best correlation to fit the measured PVT data was **Lasater** correlation for Bubble point pressure , Solution Gas Oil Ratio and Formation volume factor whereas **Beggs. et.al** correlation was used for oil viscosity. **Figure (6-13**) shows IPR Plot for well X3 where the well is able to produce 910.4 STB/day as a maximum production with a 0.634 STB/day/psi productivity index or PI.

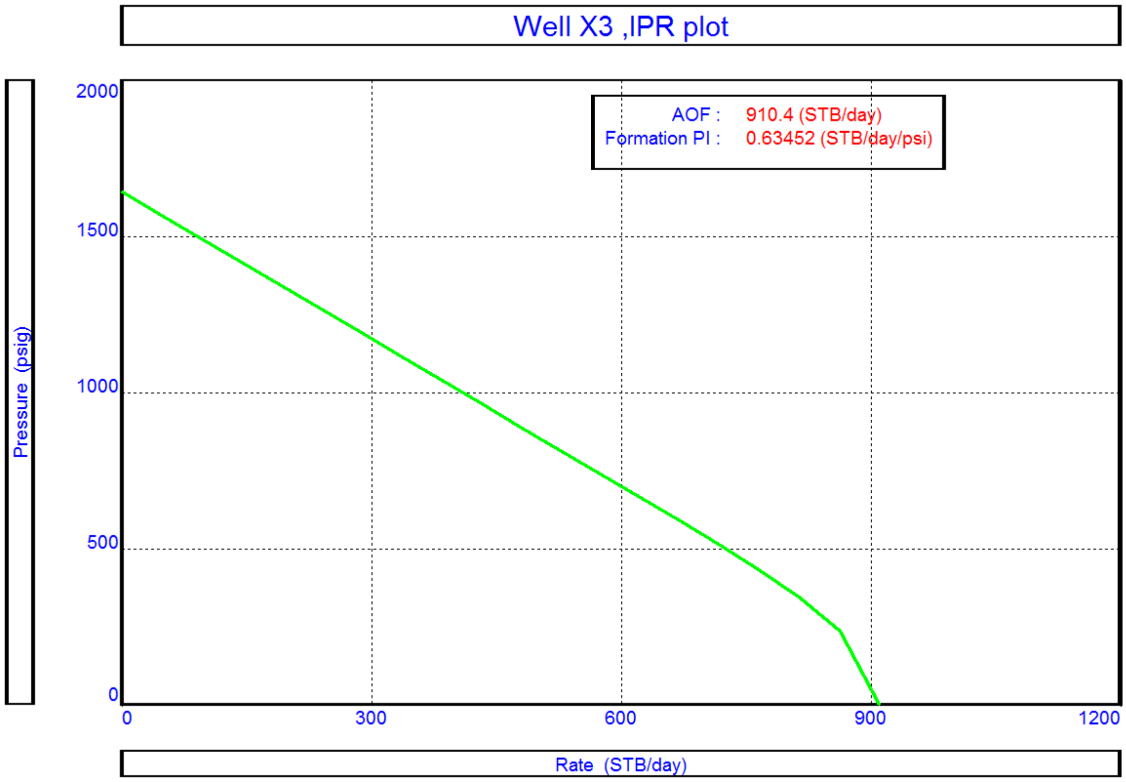

Figure (6-13) shows IPR Plot for well X3

- ***Case 1, analysis and optimization of existing ESP installation***

The pump used to flow the well is REDA 400, DN675 with 159 stages and this pump could deliver 500 STB/day. This amount of daily fluid rate can be got by less number of stages and more efficiency pump- REDA 400, DN1100- which was the results of the re-optimization process by PROSPER . **Table (6-18)** shows the minimum, maximum and the best efficiency point values for the pump at frequency 50 Hz.

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
267	569	692

Table (6-18) shows the minimum, maximum and BEP values for DN1100 ESP pump@50 Hz

The results indicated that the pump works inside its recommended operating range as well pump efficiency is increased about 3.02% comparing to the current case. **Table (6-19)** shows Re- Design results for well X3 and **Figure (6-14)** shows new pump performance curve for well X3, Case 1.

Manufacturer	REDA
Series	400
Model	DN675
Design rate, STB/day	500
Number of stages	129
Pump Efficiency, %	59.7366
Pump Setting Depth, ft	3442
Head Required	2186.38
Pump intake Pressure	618.46
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	19.5
Selected Cable	#6 Copper

Table (6-19) shows Re- Design results for well X3, Case 1.

As a quality check pressure traverses curves are plotted from top to bottom and vice-versa as it is shown in **Figure (6-15).**

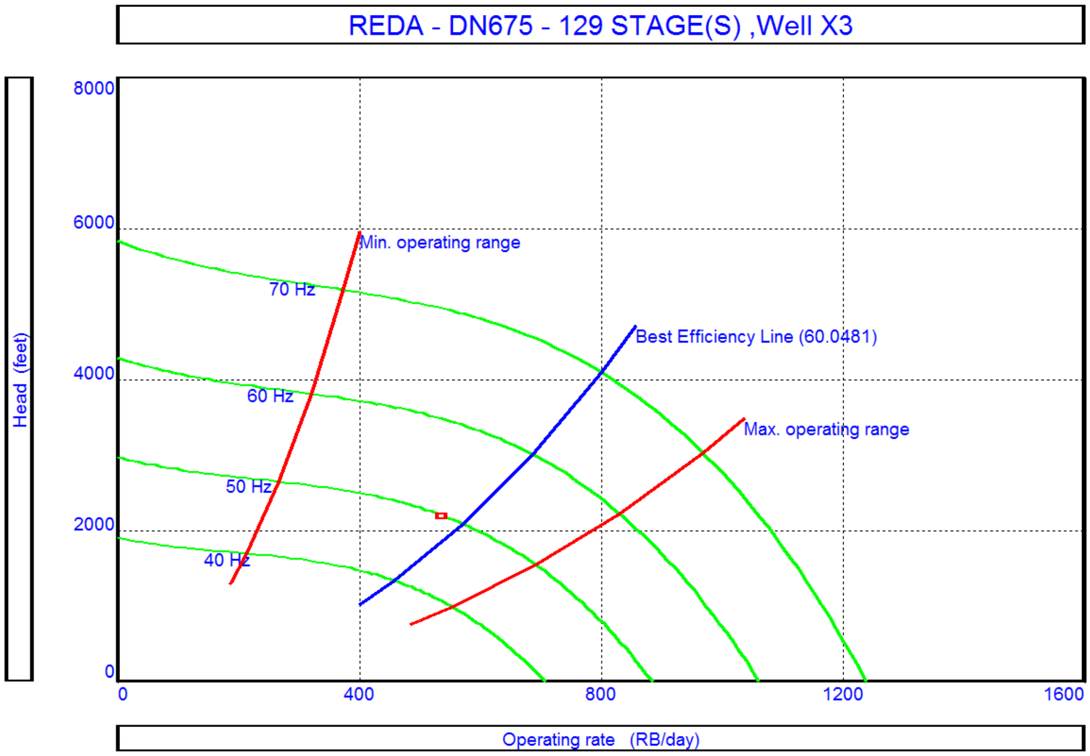

Figure (6-14) shows new pump performance curve for well X3, Case 1.

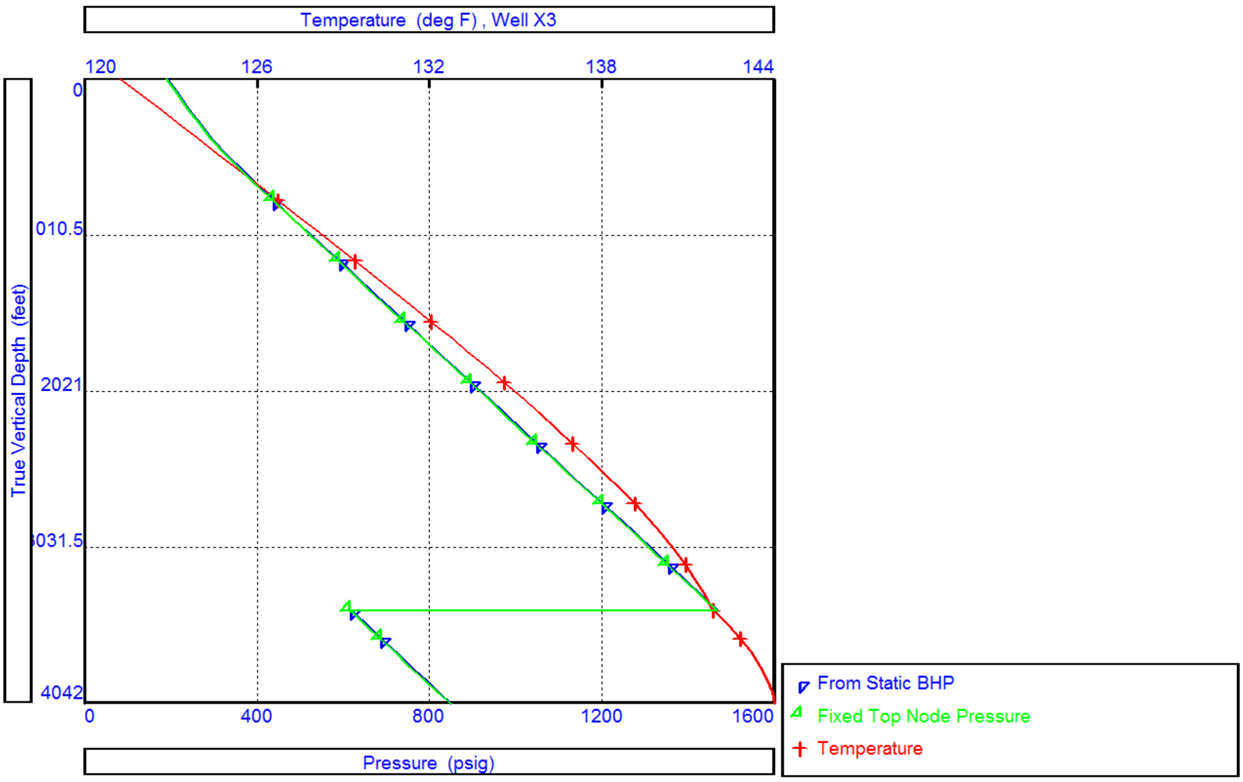

Figure (6-15) pressure traverses plot for well X3, Case 1.

- ***Case 2, analysis and optimization of new ESP installation***

In this case the design production rate was increased to be 650 STB/day taking into account that pump intake pressure is above bubble point pressure. The pump efficiency comparing to the current and first case is improved to be 61.1 % at 3700 ft pump setting depth. The new pump –REDA 400, D950 works inside its recommended operating range, **Table (6-20)**. The optimization results are shown in **Table (6-21)** and pump performance curve is shown in **Figure (6-14).**

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
500	755	958

Table (6-20) shows the minimum, maximum and BEP values for D950 ESP pump@50 Hz

Manufacturer	REDA
Series	400
Model	D950
Design rate, STB/day	650
Number of stages	174
Pump Efficiency, %	61.0623
Pump Setting Depth, ft	3700
Head Required	2770.84
Pump intake Pressure	482.222
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	25.5
Selected Cable	#1 Copper

Table (6-21) shows new design results for well X3, Case 2.

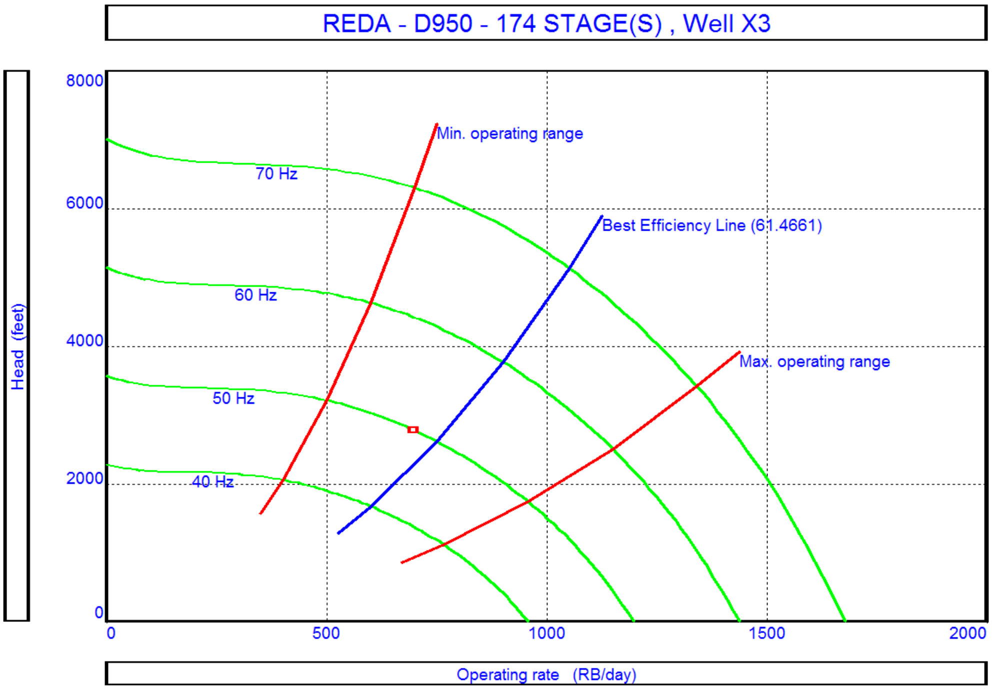

Figure (6-16) shows pump performance curve for well X3, Case 2.

The pressure traverses plot as a Quick look from top to bottom and vice-versa is shown in **Figure (6-17).**

The intersection point between pump discharge pressure curve and the vertical lift performance curve in case 2 gives us an idea about the amount of liquid can be produced. It will increase up to 150 STB/d; **Figure (6-18).**

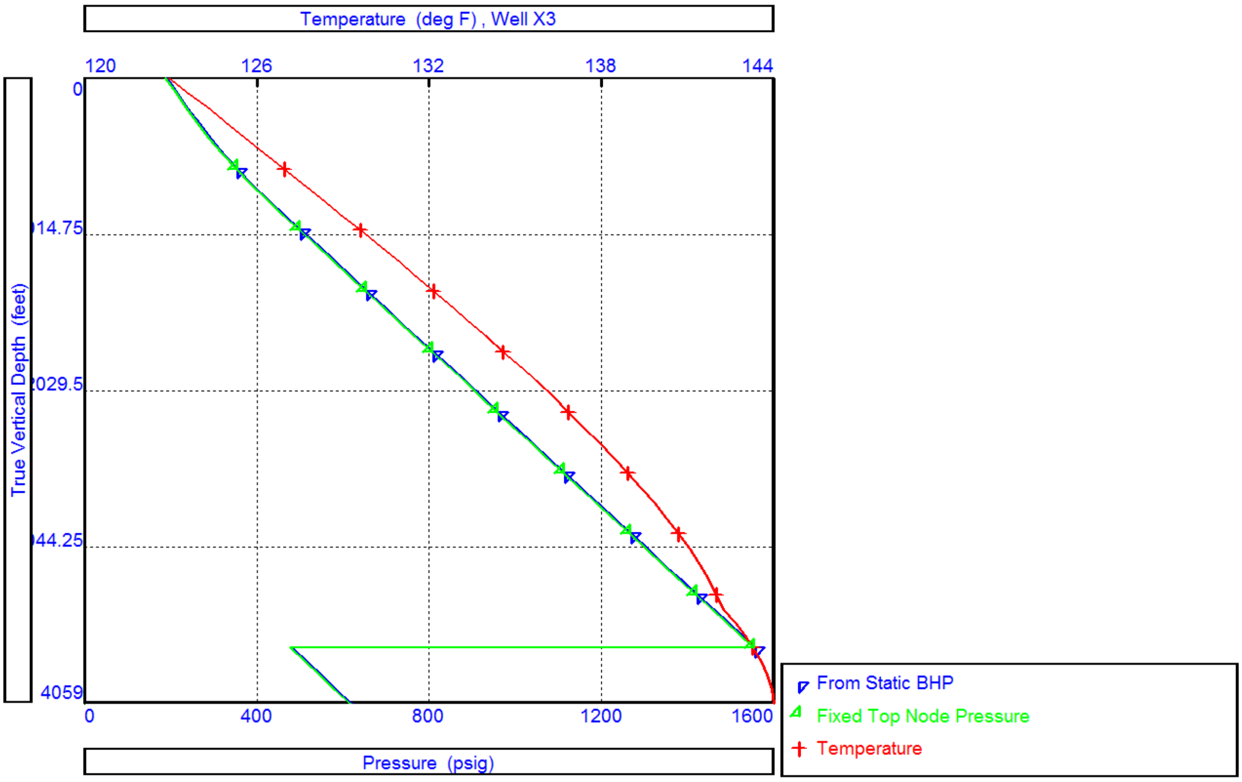

Figure (6-17) pressure traverses plot for well X3, Case 2.

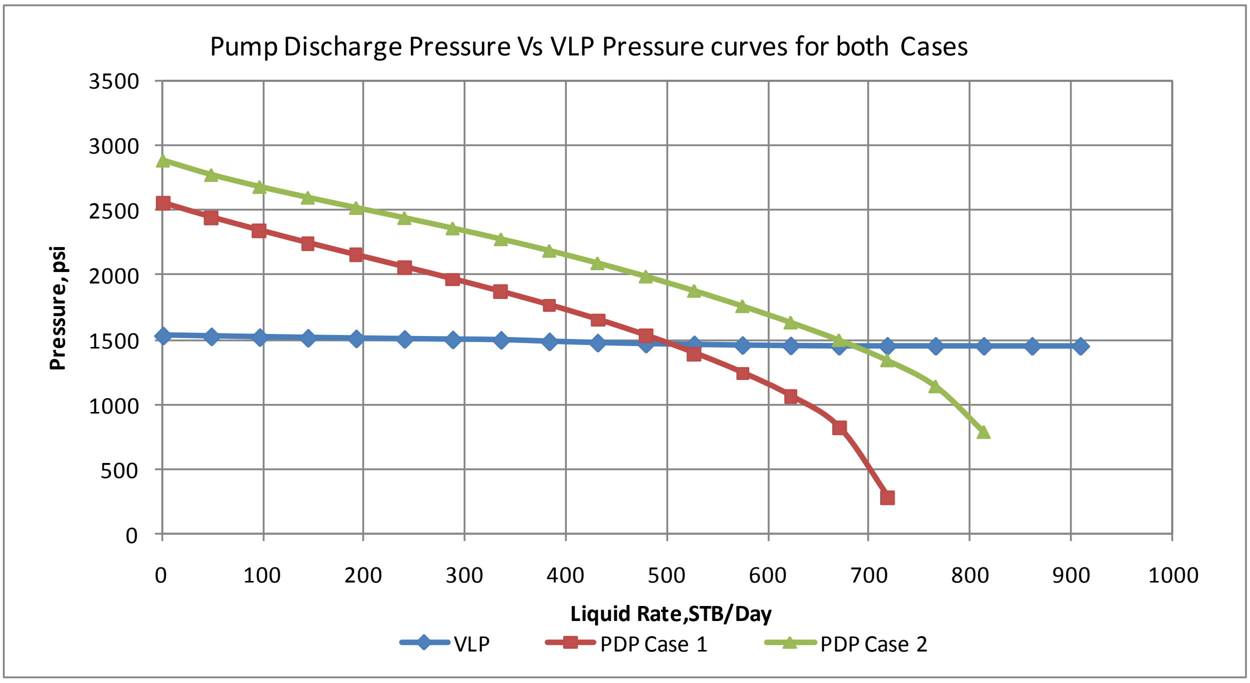

Figure (6-18) Pump discharge Pressure Vs Vertical Lift Performance plot for well X3.

6.5 Well (X-4) analysis

Completion and running ESP with Y-tool to X-4 well were performed in 1996 and last work over was applied in 2006 in order to change the failed ESP and consequently the gross flow rate modified from 549 STB/d to 819 STB/d.

Table (6-22) shows completion input data, **Table (6-23)** illustrates well production and PVT input data and **Table (6-24)** illustrates ESP design parameters that were used in PROSPER software.

Items	Setting Depth, ft	Weight, lb/ft	Size, OD, in	Grade
Casing	112	94	20	H-40
Casing	1170	68	13 3/8	J-55
Casing	4244	43.5	9 5/8	J-55
Tubing	3893	9.5	3 1/2	N-80
Perforation Depths ,ft	3984-4142			

Table (6-22) shows completion input data

Reservoir Pressure, Psi	1390
Flowing Bottom Hole Pressure, Psi	1000
Tubing Head Pressure , psi	225
Productivity Index ,bbl/day/psi	2.10
Bottom Hole Temperature ,F	144
Well Head Temperature , F	115
Water Cut ,%	40
Salinity, ppm	88,000
Solution Gas Oil Ratio , SCF/STB	183
Bubble Point Pressure , Psi	486
Oil Gravity, API	40.02
Water Specific Gravity	1.060
Gas Specific Gravity	0.855

Table (6-23) illustrates well production and PVT input data

Manufacturer	REDA
Series	400
Model	DN1000
Design rate, STB/day	819
Number of stages	229
Pump Efficiency, %	52.197
Pump Setting Depth, ft	3639
Head Required	3328.8
Pump intake Pressure	338.88
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	51
Selected Cable	#6 Copper

Table (6-24) illustrates ESP design parameters

Lasater correlation for Bubble point pressure, Solution Gas Oil Ratio and Formation volume factor and **Beggs. et.al** correlation for oil viscosity were chosen as best correlations to fit the measured PVT data .**Figure (6-19**) shows IPR Plot for well X4 where the well is able to produce 2498.6 STB/day as a maximum production with a 2.10 STB/day/psi productivity index or PI.

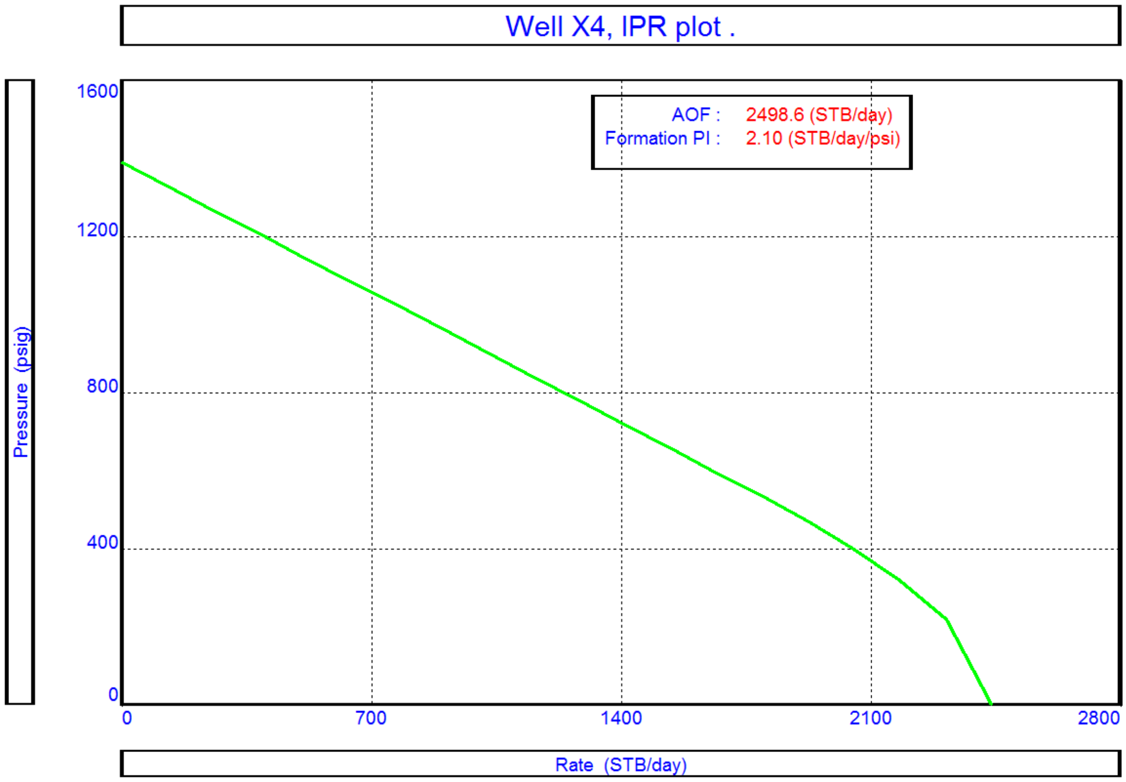

Figure (6-19) shows IPR Plot for well X4

- ***Case 1, analysis and optimization of existing ESP installation***

The existing pump used is REDA 400, DN1000 with 229 stages and the flow rate is 819 STB/day. By using PROSPER software; the re- optimization process gave the same flow rate with less number of stages by using REDA 400, DN1100. **Table (6-25)** shows the minimum, maximum and the best efficiency point values for the new pump at frequency 50 Hz.

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
500	917	1125

Table (6-25) shows the minimum, maximum and BEP values for DN1100 ESP pump@50 Hz

The results indicated that the new pump works inside its recommended operating range as well pump efficiency is improved to about 18.8% comparing to the existing case. In addition to that the new optimization pump works with pump intake pressure above bubble point pressure whereas the pump intake pressure for current case is below the bubble point. **Table (6-26)** shows Re- Design results for well X4 and **Figure (6-20)** shows new pump performance curve for well X4, Case 1.

Manufacturer	REDA
Series	400
Model	DN1100
Design rate, STB/day	819
Number of stages	123
Pump Efficiency, %	61.9855
Pump Setting Depth, ft	3639
Head Required	1998.43
Pump intake Pressure	773.591
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	22.5
Selected Cable	#1 Copper

Table (6-26) shows Re- Design results for well X4, Case 1.

As a quality check pressure traverses curves are plotted from top to bottom and vice-versa as it is shown in **Figure (6-21).**

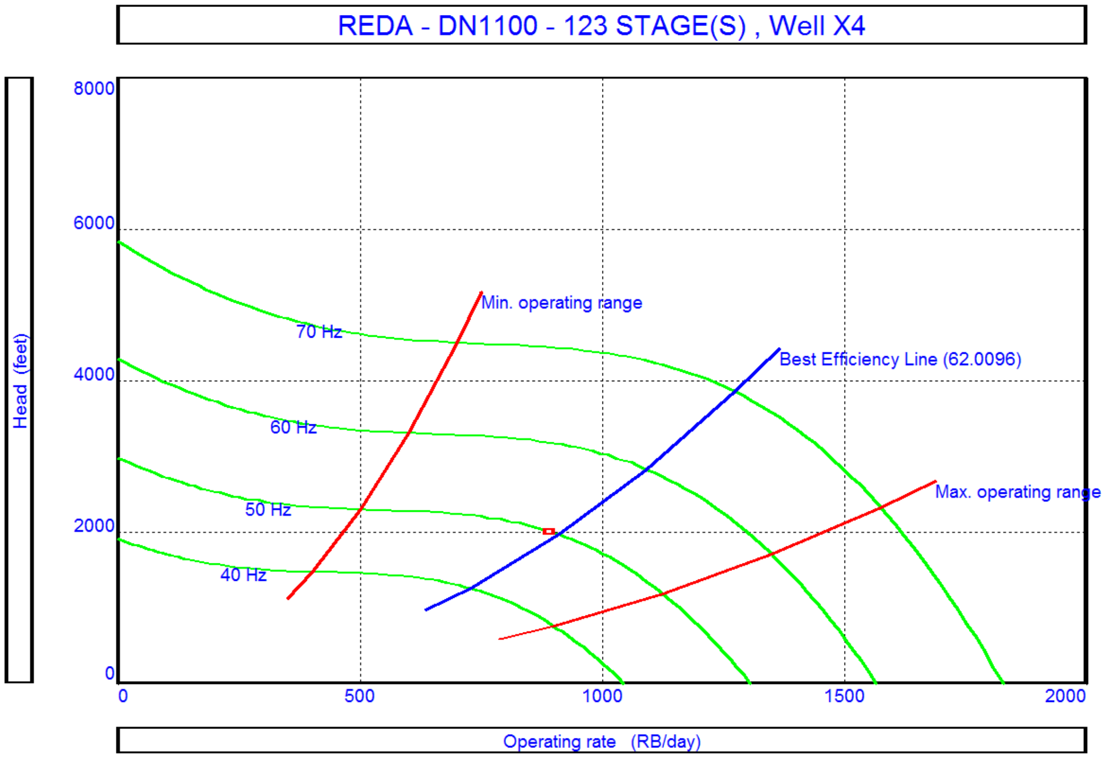

Figure (6-20) shows new pump performance curve for well X4, Case 1.

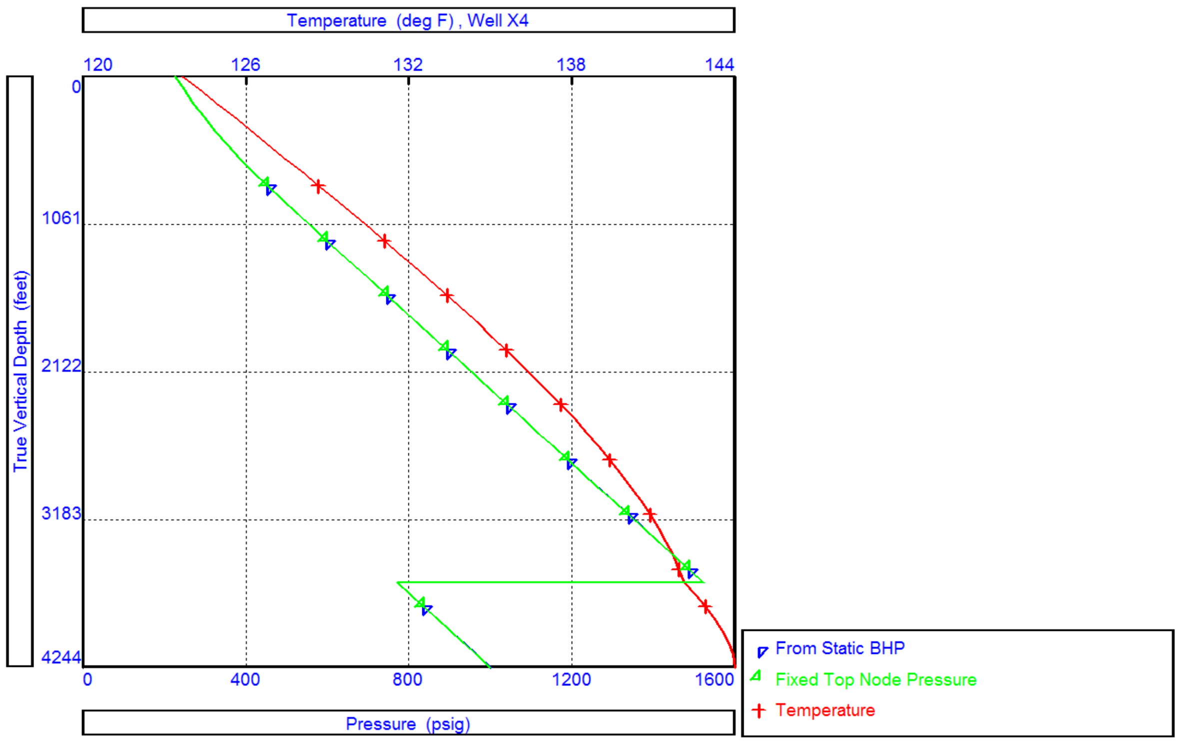

Figure (6-21) pressure traverses plot for well X4, Case 1.

- ***Case 2, analysis and optimization of new ESP installation***

In this case the design production rate is increased to be 1400 STB/day. The results showed further improvement in the pump efficiency comparing to the current and first case to be 68.5 % at the same pump setting depth. The new pump –REDA 400, DN1750 works inside its operating range near to the best efficiency point, **Table (6-27)**. The optimization results are shown in **Table (6-28)** and pump performance curve is shown in **Figure (6-22).**

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
1000	1499	1708

Table (6-27) shows the minimum, maximum and BEP values for DN1750 ESP pump@50 Hz

Manufacturer	REDA
Series	400
Model	DN1750
Design rate, STB/day	1400
Number of stages	216
Pump Efficiency, %	68.5105
Pump Setting Depth, ft	3639
Head Required	2742.81
Pump intake Pressure	497.901
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	51
Selected Cable	#1 Copper

Table (6-28) shows new design results for well X4, Case 2.

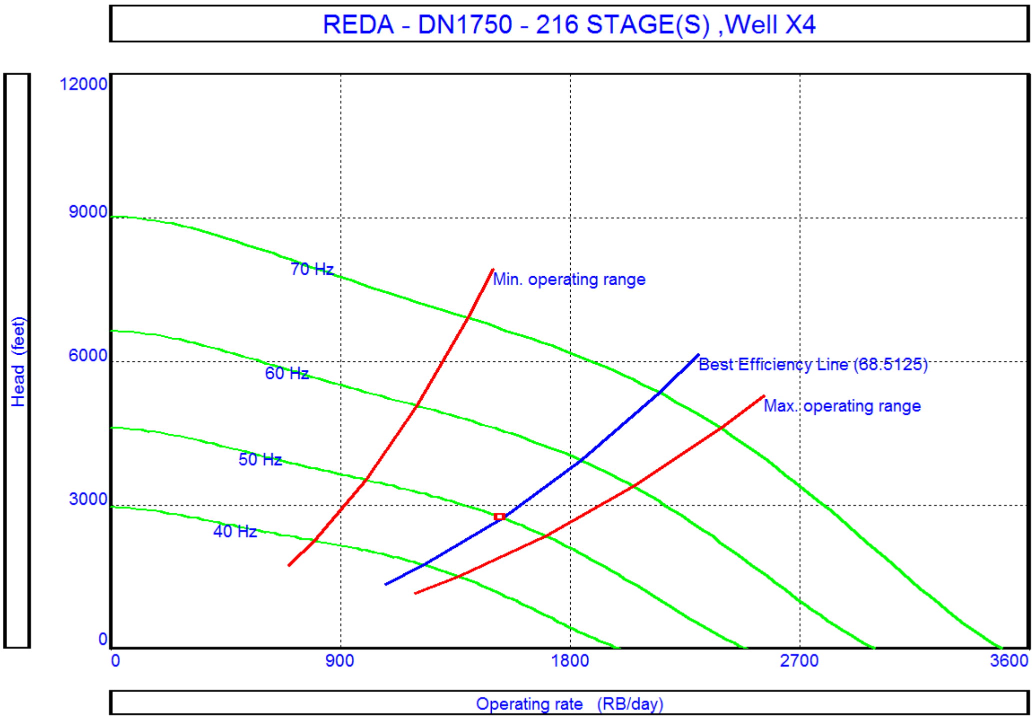

Figure (6-22) shows pump performance curve for well X4, Case 2.

The pressure traverses plot as a Quick look from top to bottom and vice-versa is shown in **Figure (6-23).**

Figure (6-24), shows Pump Discharge Pressure Vs Vertical Lift Performance plot.

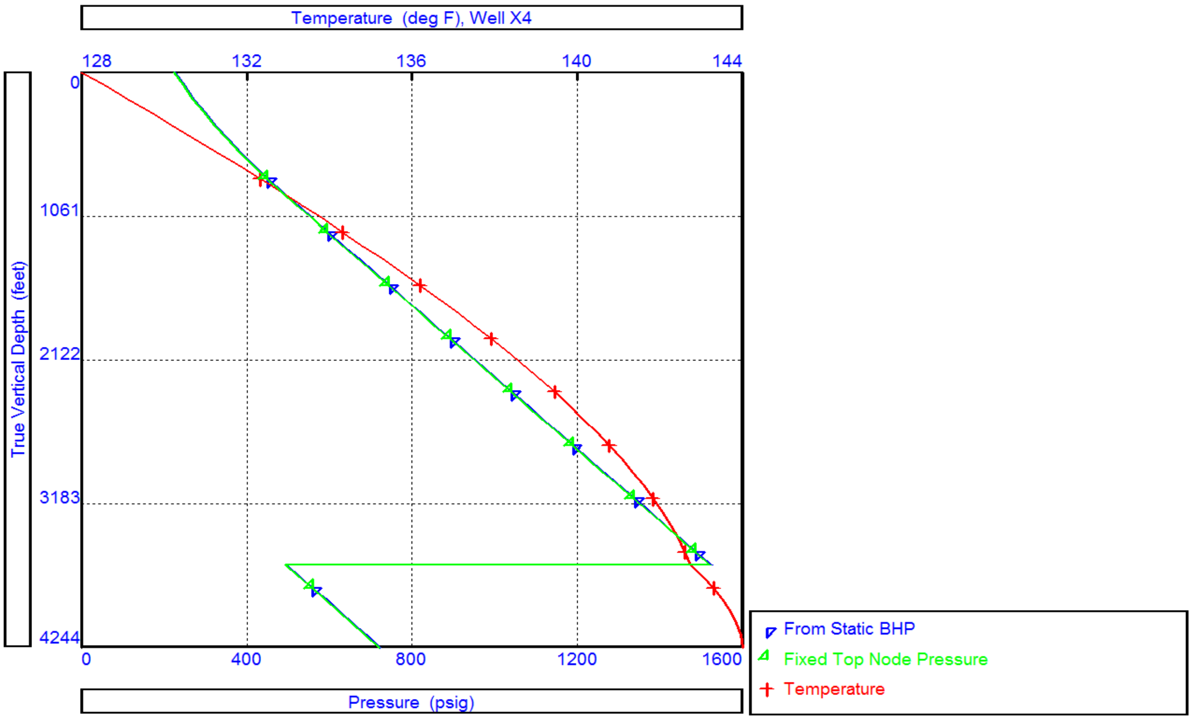

Figure (6-23) pressure traverses plot for well X4, Case 2.

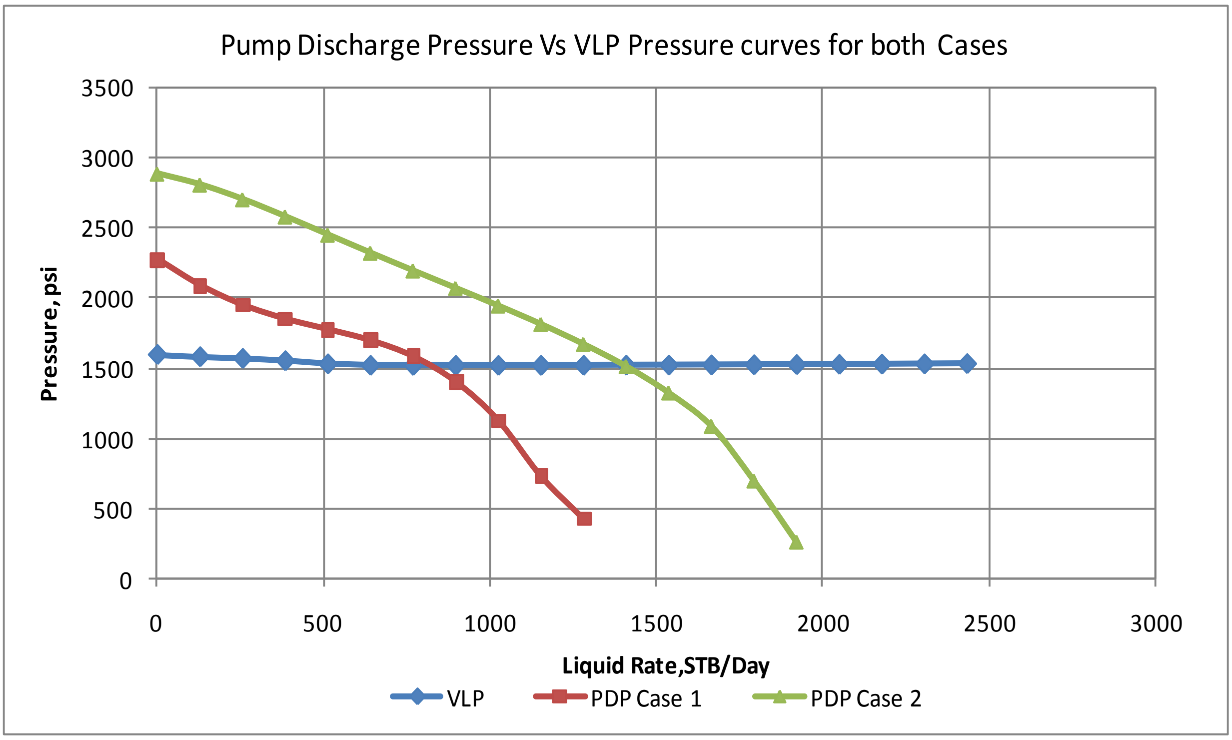

Figure (6-24) Pump discharge Pressure Vs Vertical Lift Performance plot for well X4.

6.6 Well (X-5) analysis

In 1999 well X-5 was completed after that by a year ESP was installed, the first work over job was made after that by 2 years to install Y-Tool. In 2005 ESP was pulled out and DN610, 190 stages REDA pump was installed .in Apr-2007 the pump was Re-design to be DN280 with 319 stages with the purpose of increasing the gross flow rate from 150 STB/d to 250 STB/d. **Table (6-29)** shows completion input data, **Table (6-30)** illustrates well production and PVT input data and **Table (6-31)** illustrates ESP design parameters that were used in PROSPER software.

Items	Setting Depth, ft	Weight, lb/ft	Size, OD, in	Grade
Casing	116	94	20	J-55
Casing	2190	68	13 3/8	N-80
Casing	4190	43.5	9 5/8	L-80
Tubing	4020	9.3	3 1/2	N-80
Perforation Depths ,ft	3604-4013 , 4068-4136			

Table (6-29) shows completion input data

Reservoir Pressure, Psi	1496
Flowing Bottom Hole Pressure, Psi	1050
Tubing Head Pressure , psi	150
Productivity Index ,bbl/day/psi	0.560
Bottom Hole Temperature ,F	144
Well Head Temperature , F	115
Water Cut ,%	25
Salinity, ppm	88,000
Solution Gas Oil Ratio , SCF/STB	183
Bubble Point Pressure , Psi	486
Oil Gravity, API	40.02
Water Specific Gravity	1.060
Gas Specific Gravity	0.855

Table (6-30) illustrates well production and PVT input data

Manufacturer	REDA
Series	400
Model	DN280
Design rate, STB/day	250
Number of stages	319
Pump Efficiency, %	43.680
Pump Setting Depth, ft	3455
Head Required	4403.8
Pump intake Pressure	152.26
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	10.5
Selected Cable	#4 Aluminium

Table (6-31) illustrates ESP design parameters

Lasater correlation for Bubble point pressure, Solution Gas Oil Ratio, Formation volume factor and **Beggs. et.al** correlation for oil viscosity were chosen as best correlations to fit the measured PVT data .**Figure (6-25**) shows IPR Plot for well X5 where the well is able to produce 690.1 STB/day as a maximum production with a 0.56 STB/day/psi productivity index or PI.

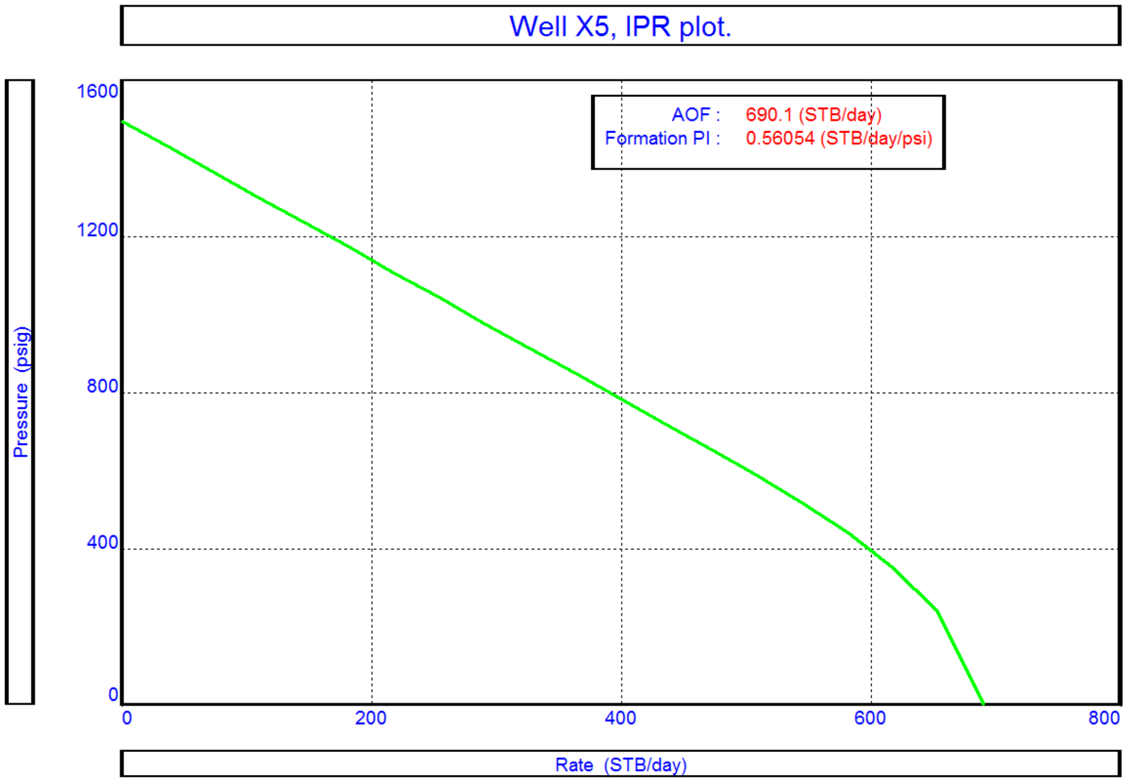

Figure (6-25) shows IPR Plot for well X5

- ***Case 1, analysis and optimization of existing ESP installation***

The existing pump used able the well to produce 250 STB/Day with 319 stages. By- re optimize the current state, the number of stages is reduced and the pump efficiency is improved to be 54.5 % instead of 43.68 % with the same pump. **Table (6-32)** shows the minimum, maximum and the best efficiency point values for the pump at frequency 50 Hz.

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
83	323	375

Table (6-32) shows the minimum, maximum and BEP values for DN280 ESP pump@50 Hz

The results indicated that the new pump works inside its recommended operating range .besides that the new optimized pump works with pump intake pressure above bubble point pressure whereas the pump intake pressure for existing pump is below the bubble point pressure. **Table (6-33)** shows Re- Design results for well X5 and **Figure (6-26)** shows new pump performance curve for well X5, Case 1.

Manufacturer	REDA
Series	400
Model	DN280
Design rate, STB/day	250
Number of stages	108
Pump Efficiency, %	54.5471
Pump Setting Depth, ft	3455
Head Required	1247.92
Pump intake Pressure	789.504
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	7.5
Selected Cable	#4 Aluminium

Table (6-33) shows Re- Design results for well X5, Case 1.

As a quality check pressure traverses curves are plotted from top to bottom and vice-versa as it is shown in **Figure (6-27).**

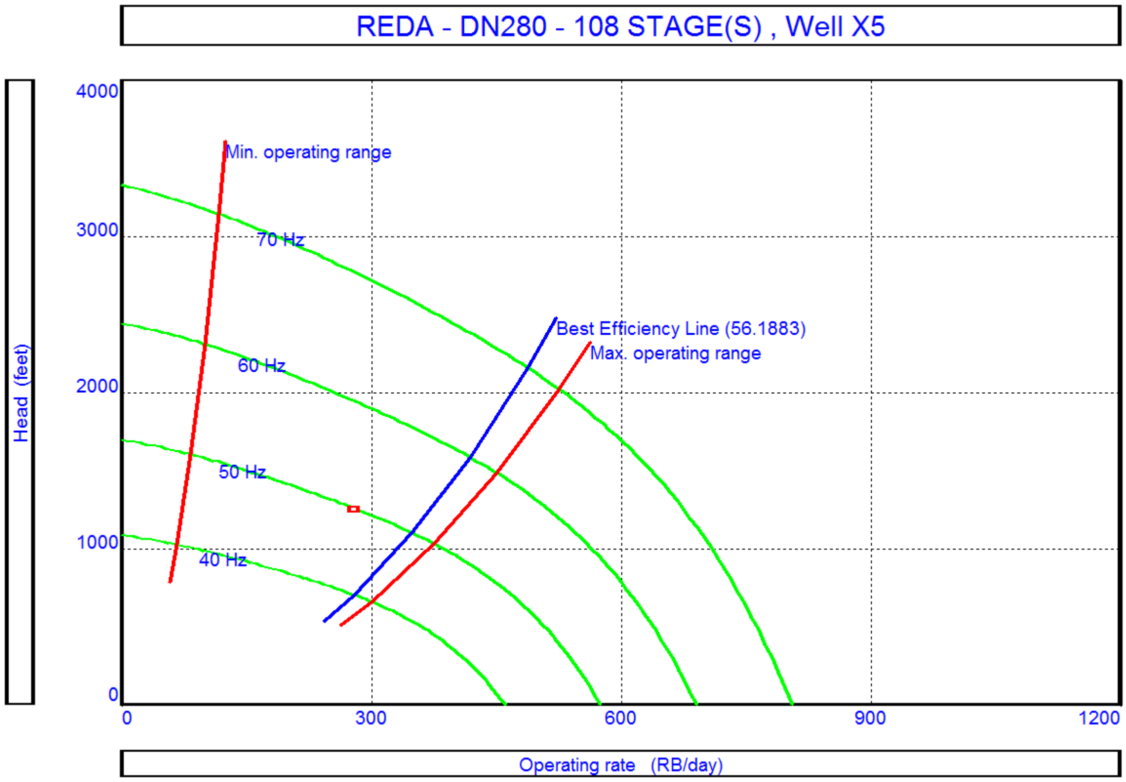

Figure (6-26) shows new pump performance curve for well X5, Case 1.

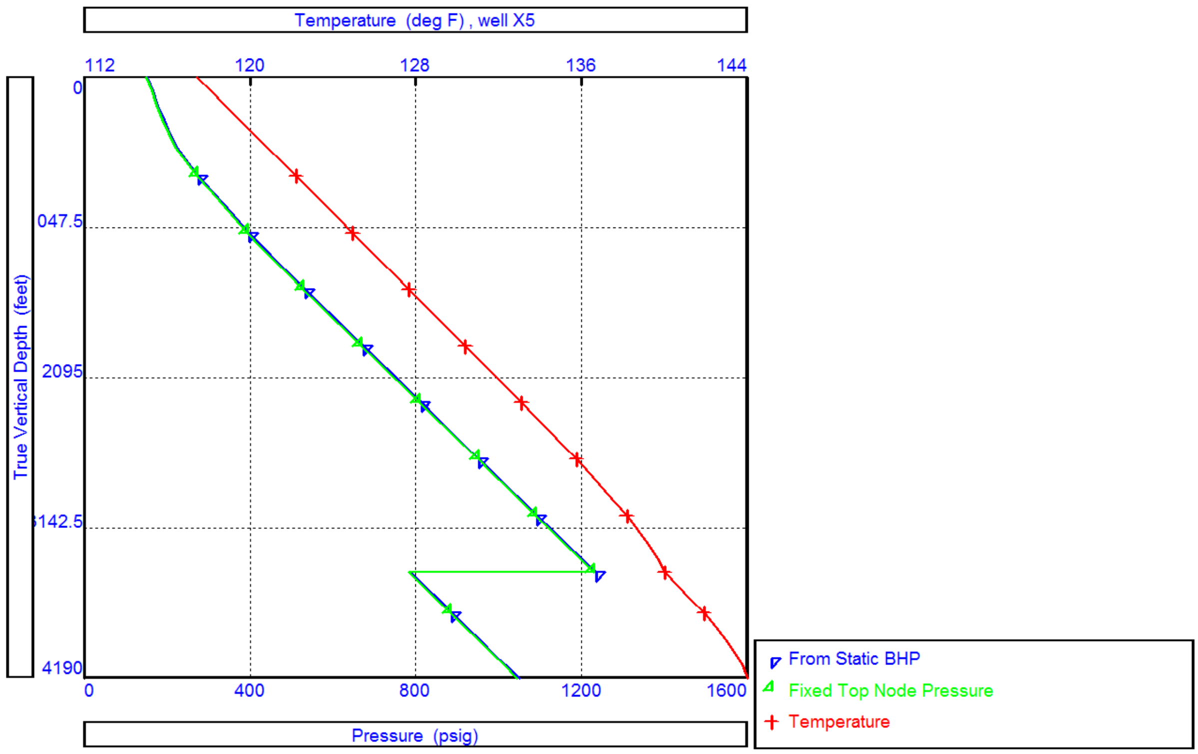

Figure (6-27) pressure traverses plot for well X5, Case 1.

- ***Case 2, analysis and optimization of new ESP installation***

The design production rate is increased to be 400 STB/day. The results presented a reduction in the pump efficiency comparing to the first case but still better than the current case at the same pump setting depth. The new pump –REDA 400, DN525 works inside its operating range, **Table (6-34)**. The optimization results are shown in **Table (6-35)** and pump performance curve is shown in **Figure (6-28).**

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
250	438	517

Table (6-34) shows the minimum, maximum and BEP values for DN525 ESP pump@50 Hz

Manufacturer	REDA
Series	400
Model	DN525
Design rate, STB/day	400
Number of stages	161
Pump Efficiency, %	52.5707
Pump Setting Depth, ft	3455
Head Required	1846.05
Pump intake Pressure	523.321
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	15
Selected Cable	#1 Copper

Table (6-35) shows new design results for well X5, Case 2.

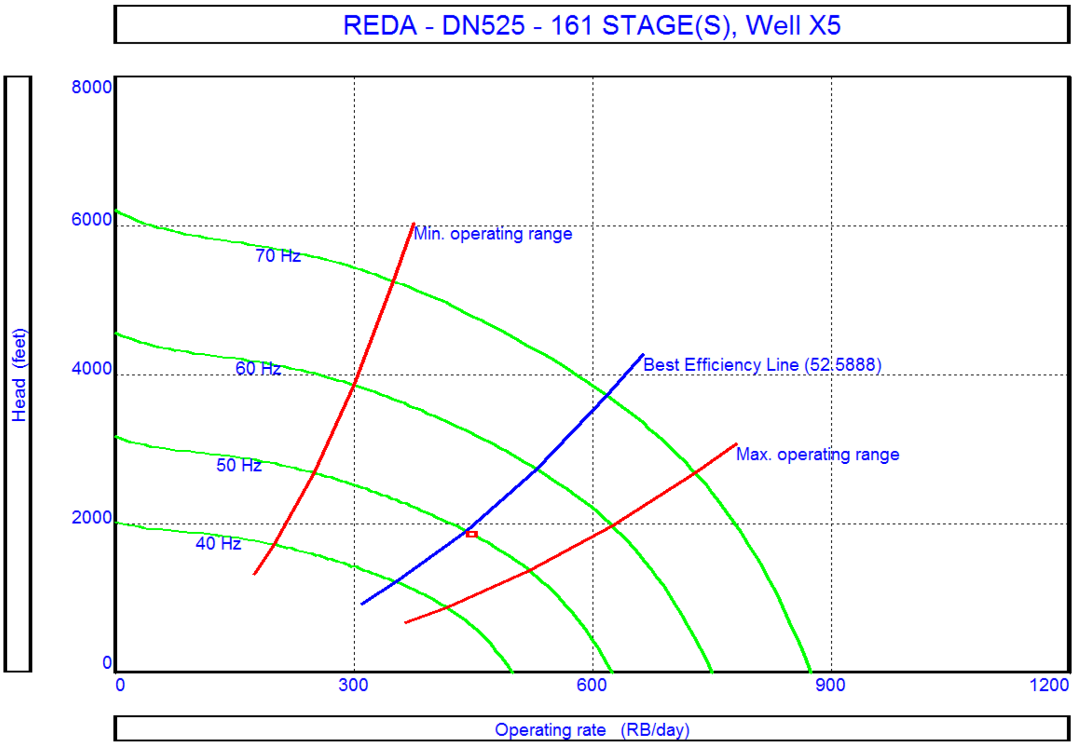

Figure (6-28) shows pump performance curve for well X5, Case 2.

The pressure traverses plot as a Quick look from top to bottom and vice-versa is shown in **Figure (6-29).**

Pump discharge Pressure Vs Vertical lift Performance curve for two cases in **Figure (6-30).**

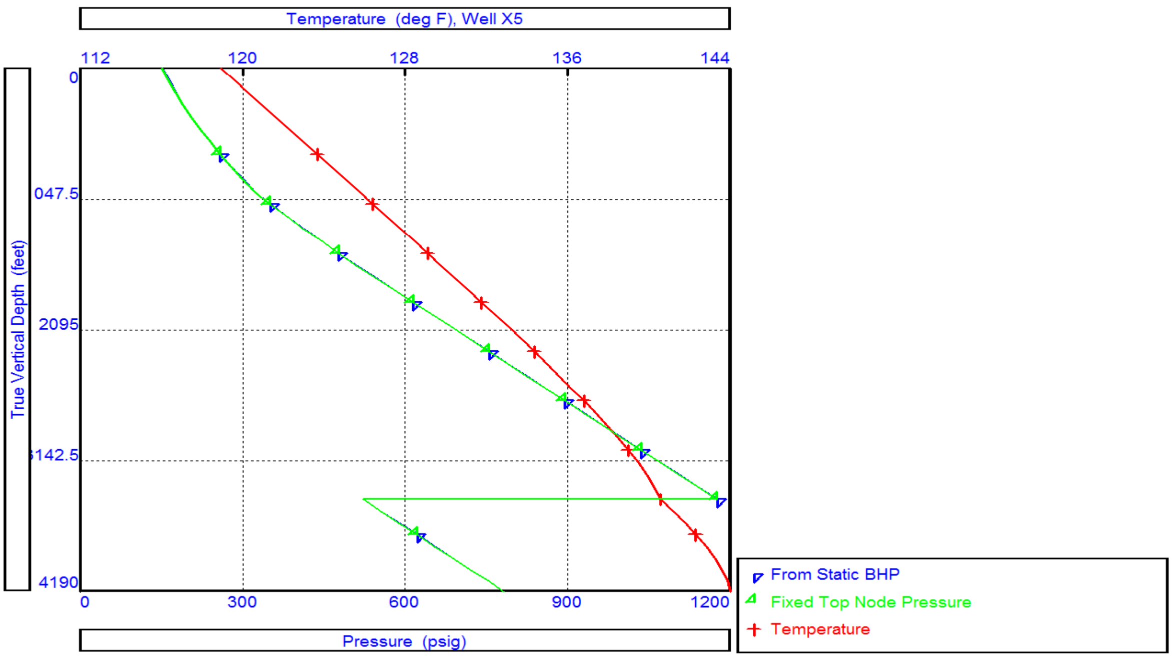

Figure (6-29) pressure traverses plot for well X5, Case 2.

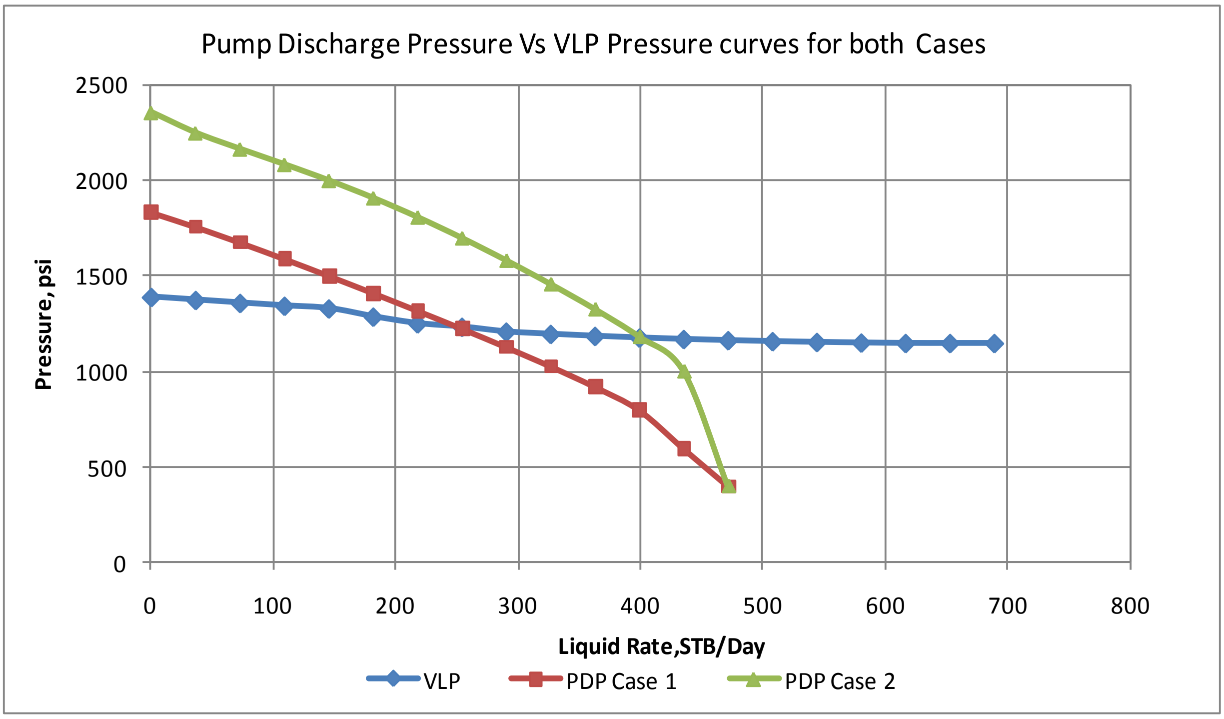

Figure (6-30) Pump discharge Pressure Vs Vertical Lift Performance plot for well X5.

6.7 Well (X-6) analysis

Well X-6 was completed in 2001 and the first ESP (DN610, 153 stages) was installed in 2003 as a result of the drop in gross flow rate more than 29 % to about 153 STB/d, in 2007 , REDA 400, D475N ESP has been used and it helps to produce 366 STB/d. **Table (6-36)** shows completion input data, **Table (6-37)** illustrates well production and PVT input data and **Table (6-38)** illustrates ESP design parameters that were used in PROSPER software.

Items	Setting Depth, ft	Weight, lb/ft	Size, OD, in	Grade
Casing	118	94	20	J-55
Casing	993	68	13 3/8	N-80
Casing	4091	43.5	9 5/8	L-80
Tubing	3600	9.3	3 1/2	L-80
Perforation Depths ,ft	3642-3813 , 3889-4046			

Table (6-36) shows completion input data

Reservoir Pressure, Psi	1510
Flowing Bottom Hole Pressure, Psi	620
Tubing Head Pressure , psi	200
Productivity Index ,bbl/day/psi	0.411
Bottom Hole Temperature ,F	144
Well Head Temperature , F	115
Water Cut ,%	65
Salinity, ppm	88,000
Solution Gas Oil Ratio , SCF/STB	183
Bubble Point Pressure , Psi	486
Oil Gravity, API	40.02
Water Specific Gravity	1.060
Gas Specific Gravity	0.855

Table (6-37) illustrates well production and PVT input data

Manufacturer	REDA
Series	400
Model	D475N
Design rate, STB/day	366
Number of stages	158
Pump Efficiency, %	50.755
Pump Setting Depth, ft	3604
Head Required	2601.9
Pump intake Pressure	458.59
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	15
Selected Cable	#1 Aluminium

Table (6-38) illustrates ESP design parameters

Lasater correlation for Bubble point pressure, Solution Gas Oil Ratio, Formation volume factor and **Beggs. Et.al** correlations for oil viscosity were chosen as best correlations to fit the measured PVT data. **Figure (6-31**) shows IPR Plot for well X6 where the well is able to produce 541.7 STB/day as a maximum production with a 0.41 STB/day/psi productivity index or PI.

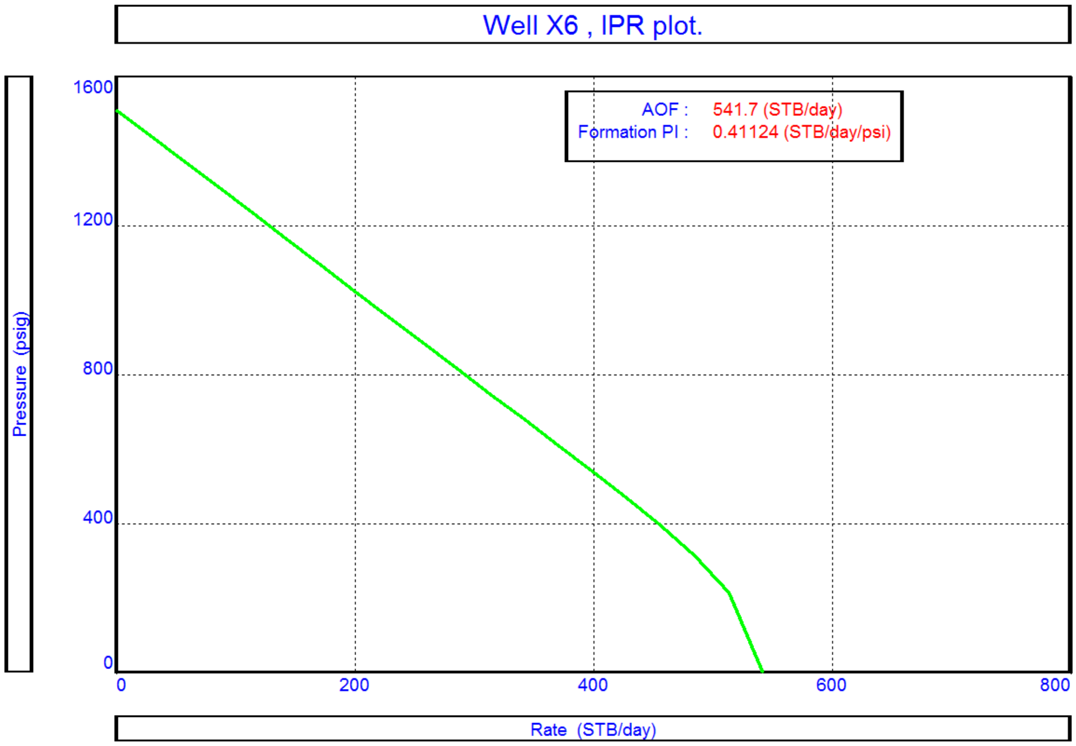

Figure (6-31) shows IPR Plot for well X6

- ***Case 1, analysis and optimization of existing ESP installation***

The current pump used able the well to produce 366 STB/Day with 158 stages. In the re optimization process that was done and in order to keep the pump intake pressure above the bubble point pressure, it was apparent that number of stages must be increased in this case to be 182 to have 518 psi pump intake pressure. Additionally, pump setting depth must be changed and the same existing pump type was chosen. **Table (6-39)** shows the minimum, maximum and the best efficiency point values for the used pump at frequency 50 Hz.

Minimum operating range, STB/day	Best Efficiency Point , STB/day	Maximum operating range, STB/day
167	382	520

Table (6-39) shows the minimum, maximum and BEP values for D475N ESP pump@50 Hz

The used pump works inside its operating range. **Table (6-40)** shows Re- Design results for well X6 and **Figure (6-32)** shows new pump performance curve for well X6, Case 1.

Manufacturer	REDA
Series	400
Model	D475N
Design rate, STB/day	366
Number of stages	182
Pump Efficiency, %	50.7969
Pump Setting Depth, ft	3841
Head Required	3023.98
Pump intake Pressure	518.834
Design Frequency, Hz	50
Motor Type	Reda375_87_Std
Nameplate Power, HP	19.5
Selected Cable	#6 Copper

Table (6-40) shows Re- Design results for well X6, Case 1.

As a quality check pressure traverses curves are plotted from top to bottom and vice-versa as it is shown in **Figure (6-33).**

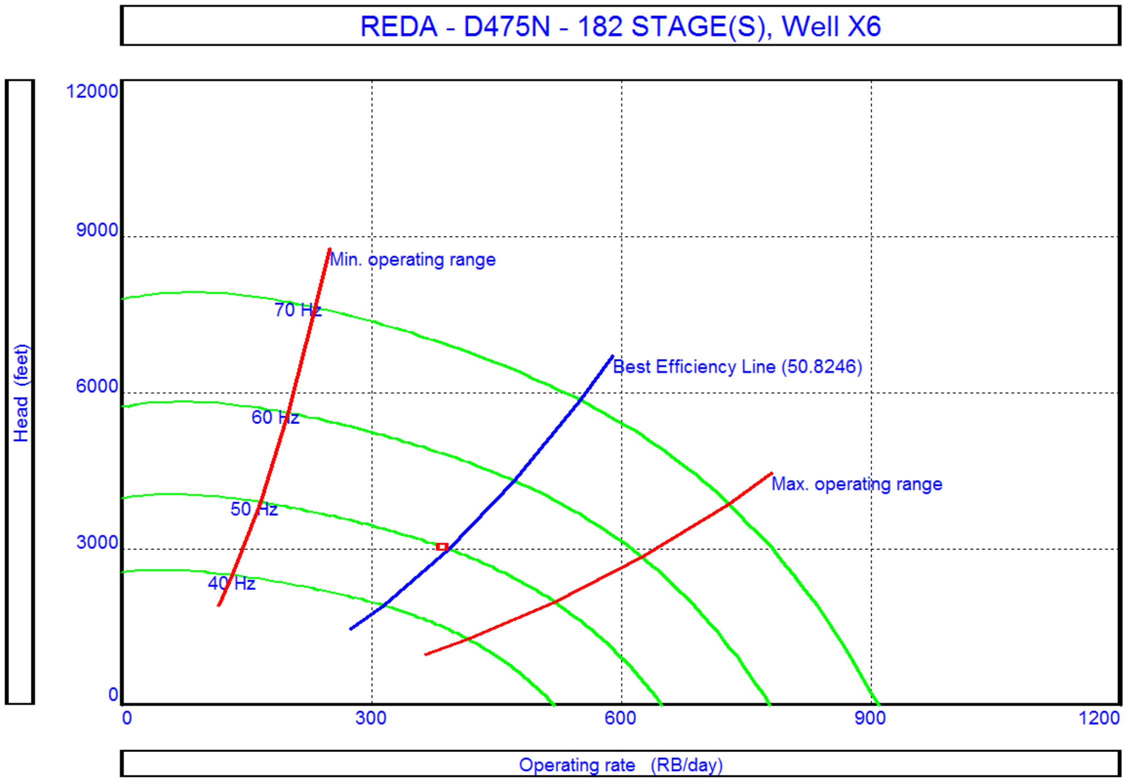

Figure (6-32) shows new pump performance curve for well X6, Case 1.

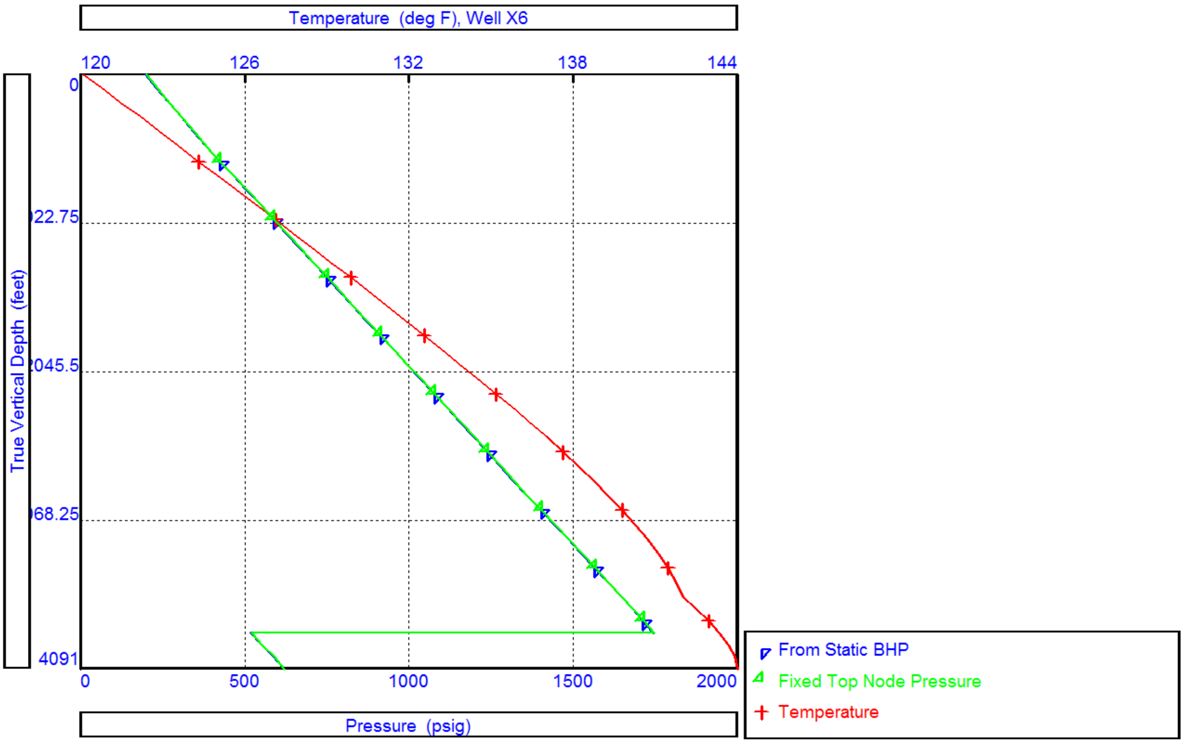

Figure (6-33) pressure traverses plot for well X6, Case 1.

- ***Case 2, analysis and optimization of new ESP installation***

  After applying the optimization process trying to increase the design rate, it was clear that keeping pump intake pressure above bubble point pressure will be achieved if the current pump REDA 400, D475N with 182 stages and 3841 ft pump setting depth are chosen. There was no new pump better than the one used in the first case for well X6.

6.8 Sensitivity analysis

One of the useful techniques that helped to choose the optimum operating conditions for the ESP lifted wells is to construct a sensitivity analysis chart between number of stages and possible Liquid production rates and see how it can effect on the pump efficiency and horsepower required. As well pump intake pressure is taken into account to compare between the current case and the optimum one either in ***case 1*** or in ***case 2***. The following graphs show the results for the six wells.

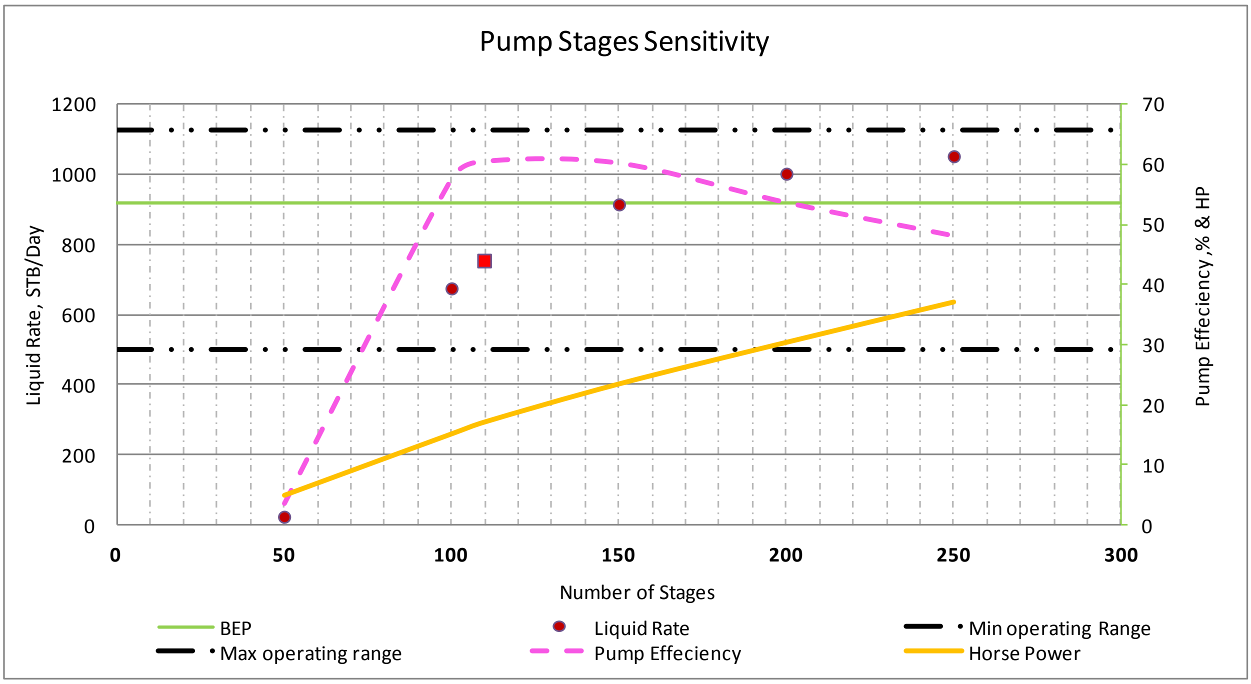

Figure (6-34) Liquid Rate, Pump efficiency and Horsepower Vs Number of stages- well X1, Case 1.

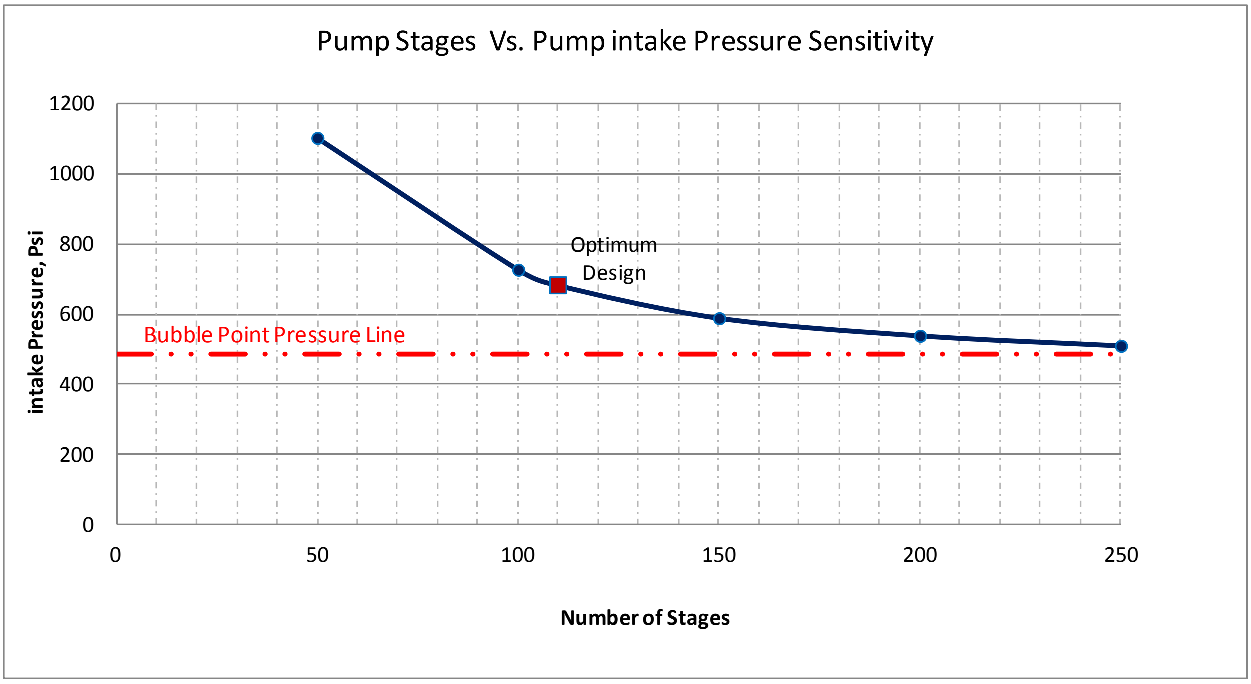

Figure (6-35) Pump intake Pressure Vs Number of stages- well X1, Case 1.

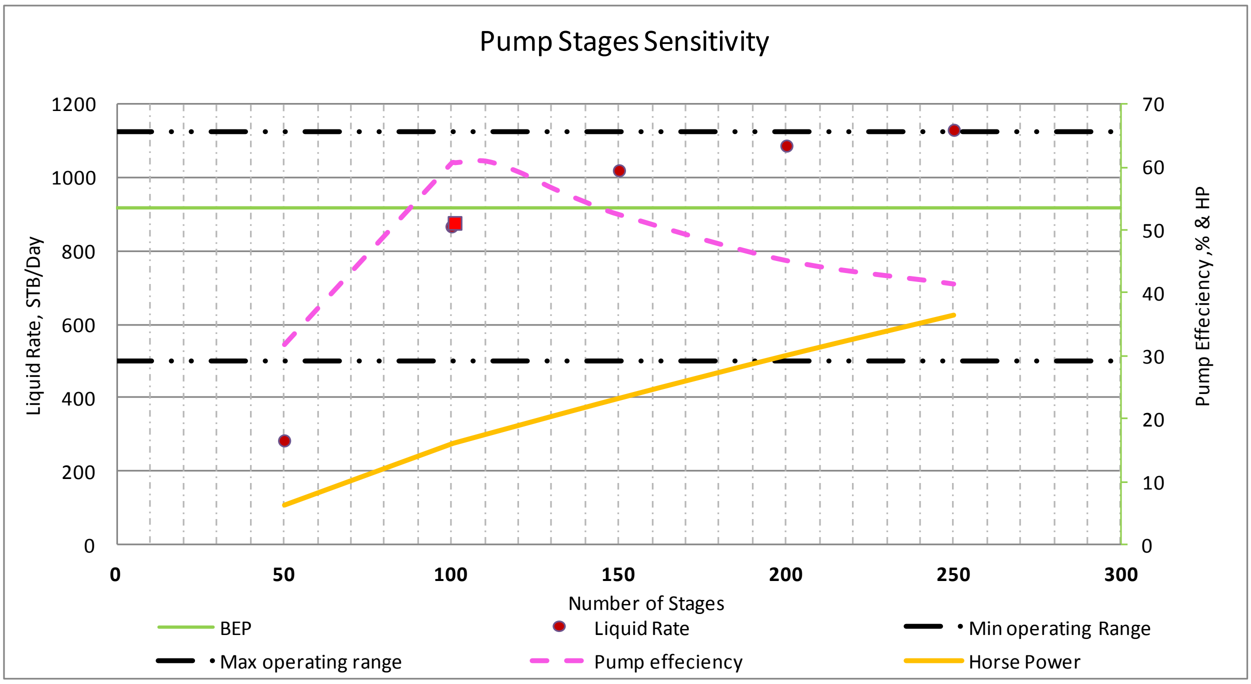

Figure (6-36) Liquid Rate, Pump efficiency and Horsepower Vs Number of stages- well X2, Case 1.

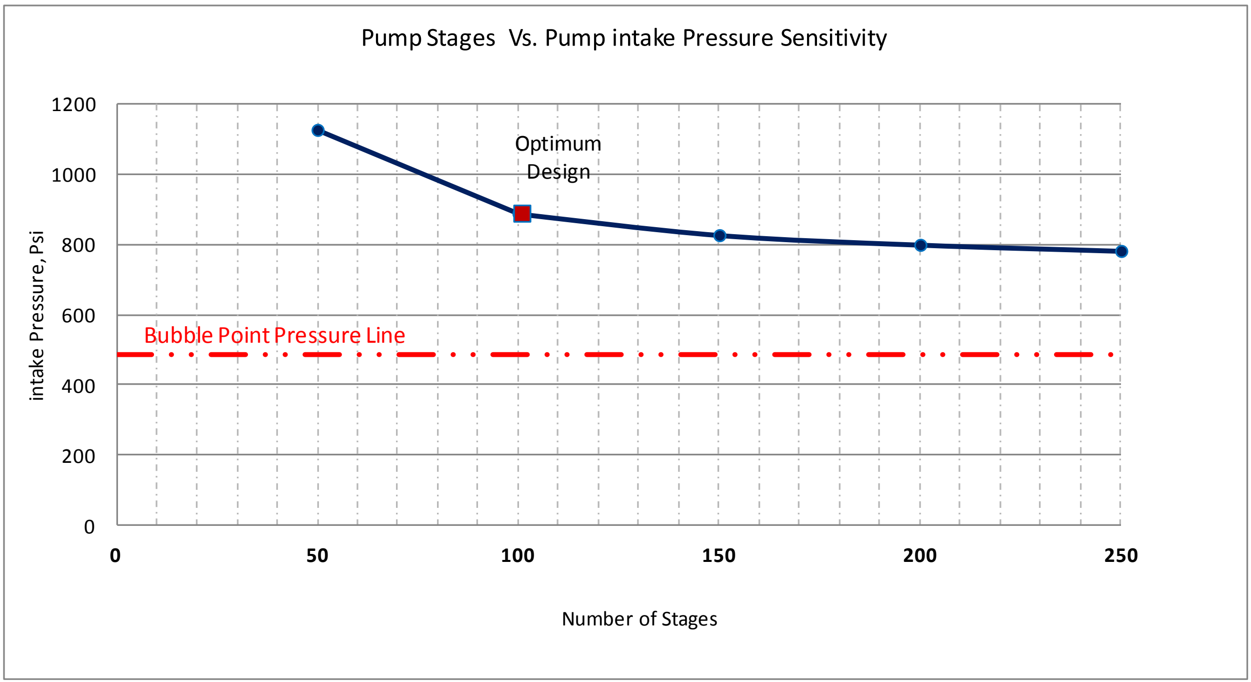

Figure (6-37) Pump intake Pressure Vs Number of stages- well X2, Case 1.

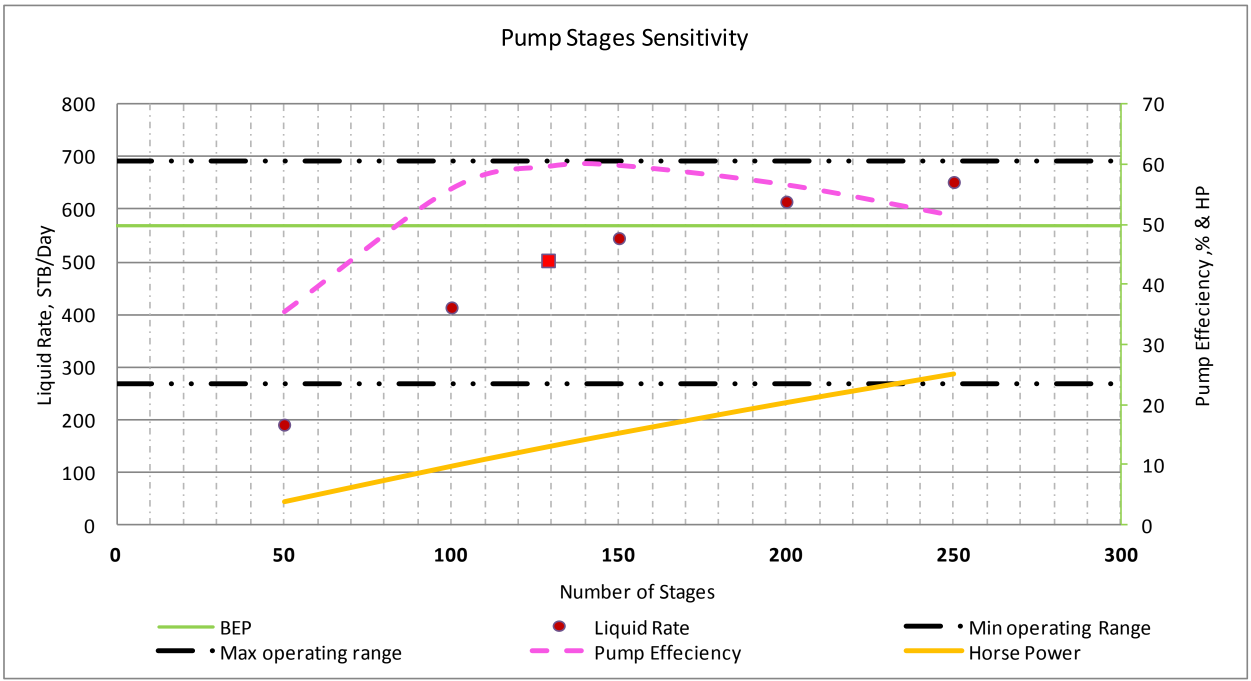

Figure (6-38) Liquid Rate, Pump efficiency and Horsepower Vs Number of stages- well X3, Case 1.

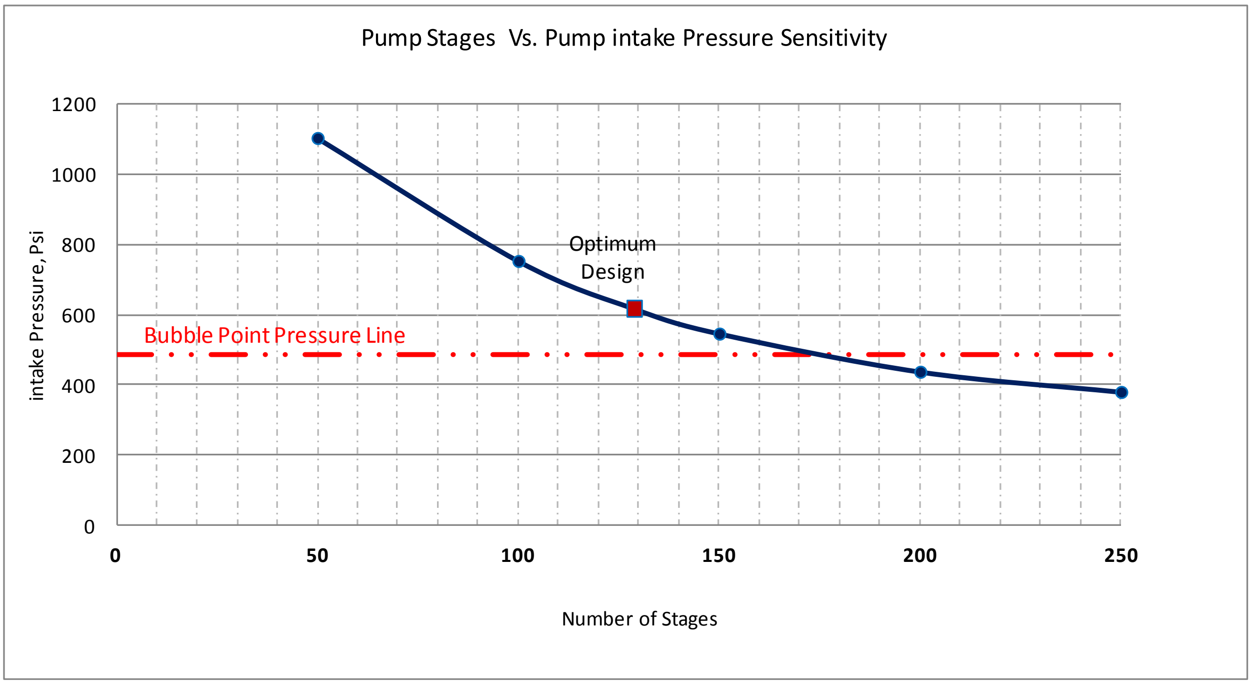

Figure (6-39) Pump intake Pressure Vs Number of stages- well X3, Case 1.

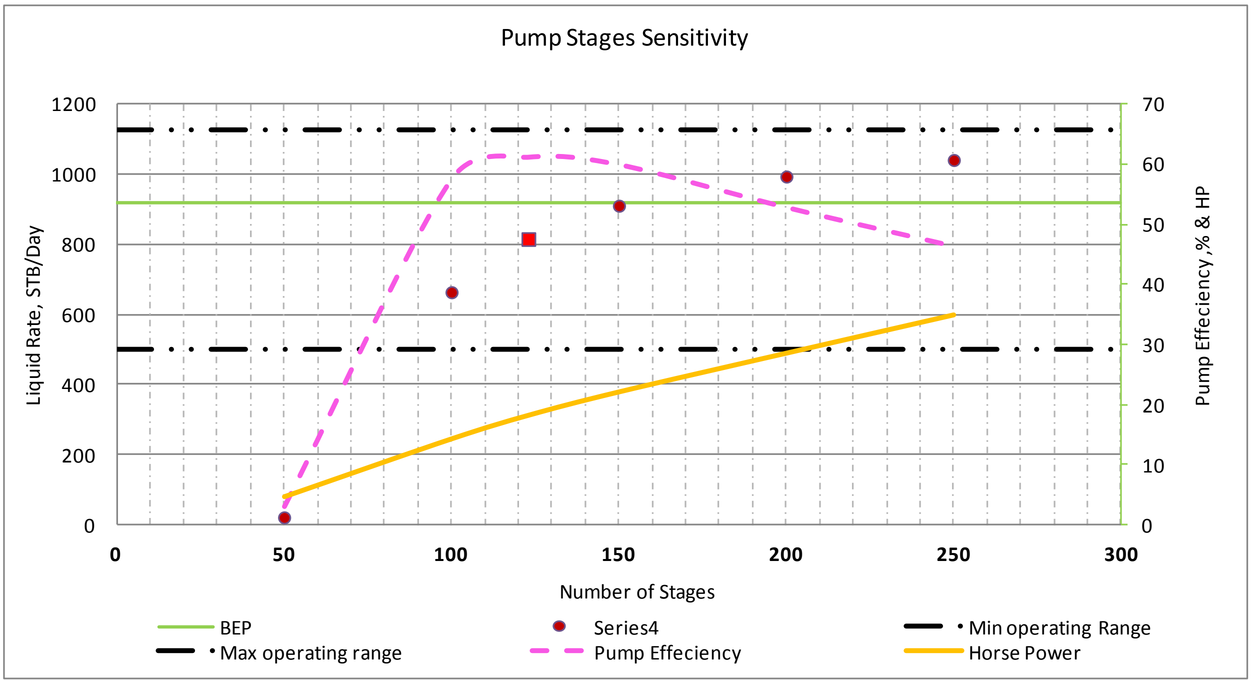

Figure (6-40) Liquid Rate, Pump efficiency and Horsepower Vs Number of stages- well X4, Case 1.

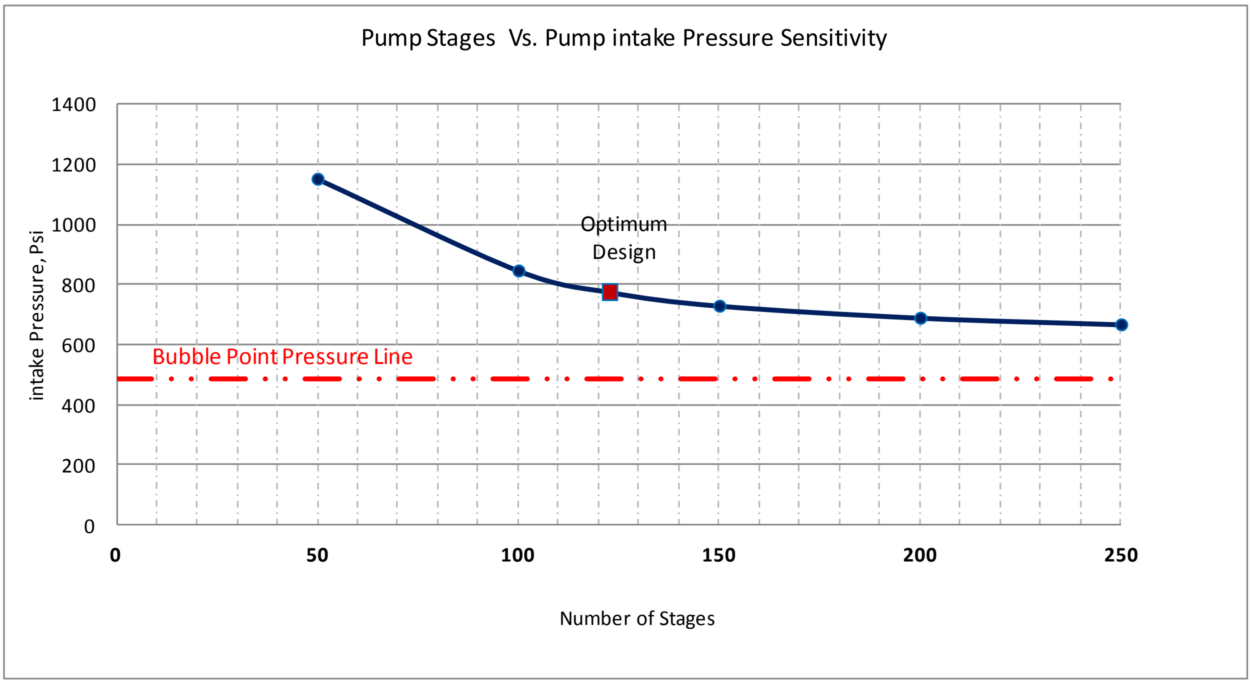

Figure (6-41) Pump intake Pressure Vs Number of stages- well X4, Case 1.

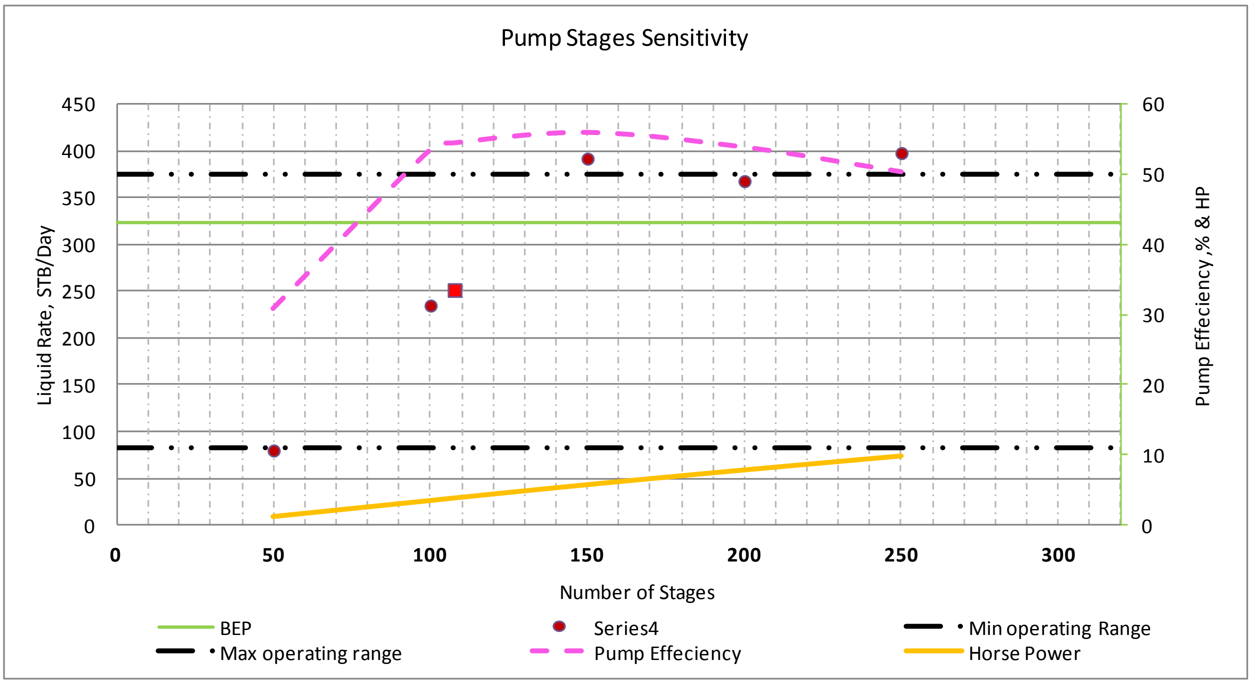

Figure (6-42) Liquid Rate, Pump efficiency and Horsepower Vs Number of stages- well X5, Case 1.

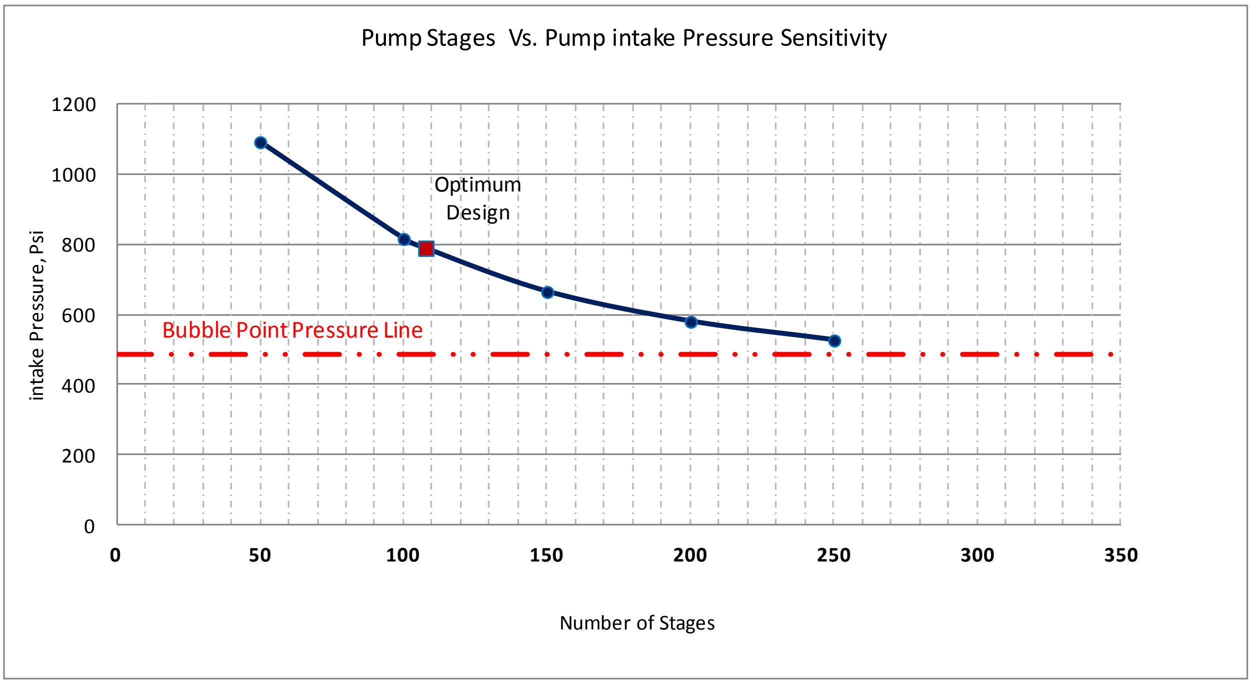

Figure (6-43) Pump intake Pressure Vs Number of stages- well X5, Case 1.

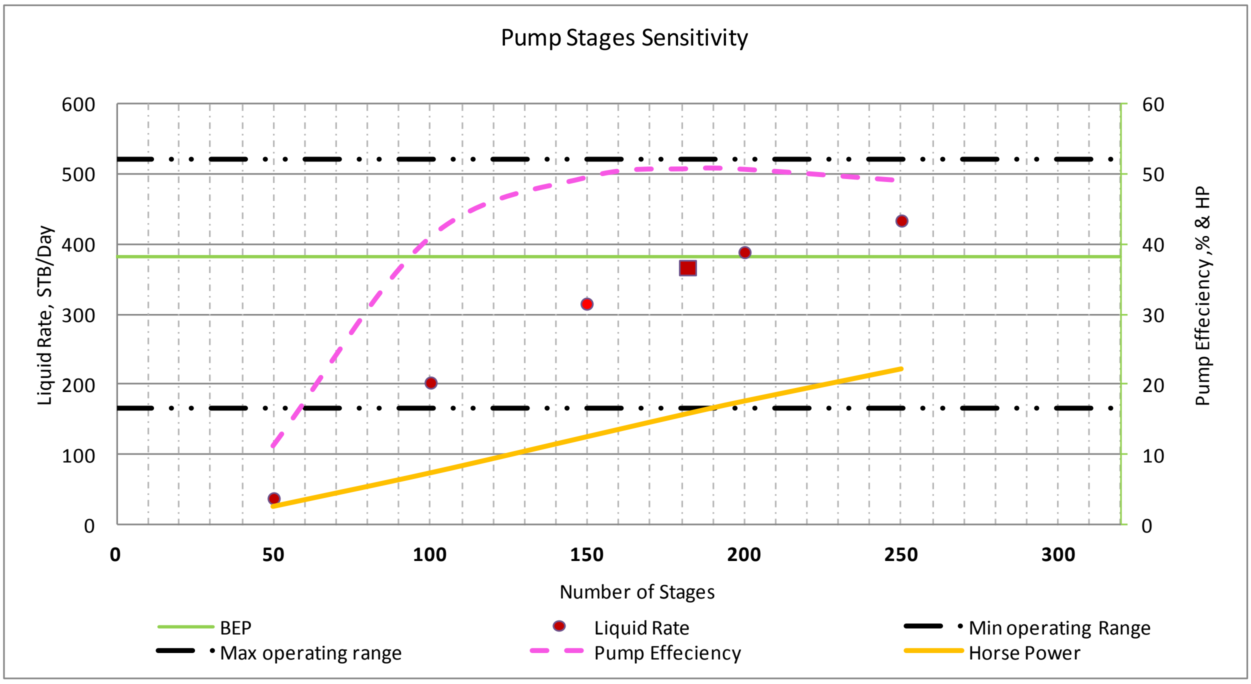

Figure (6-44) Liquid Rate, Pump efficiency and Horsepower Vs Number of stages- well X6, Case 1.

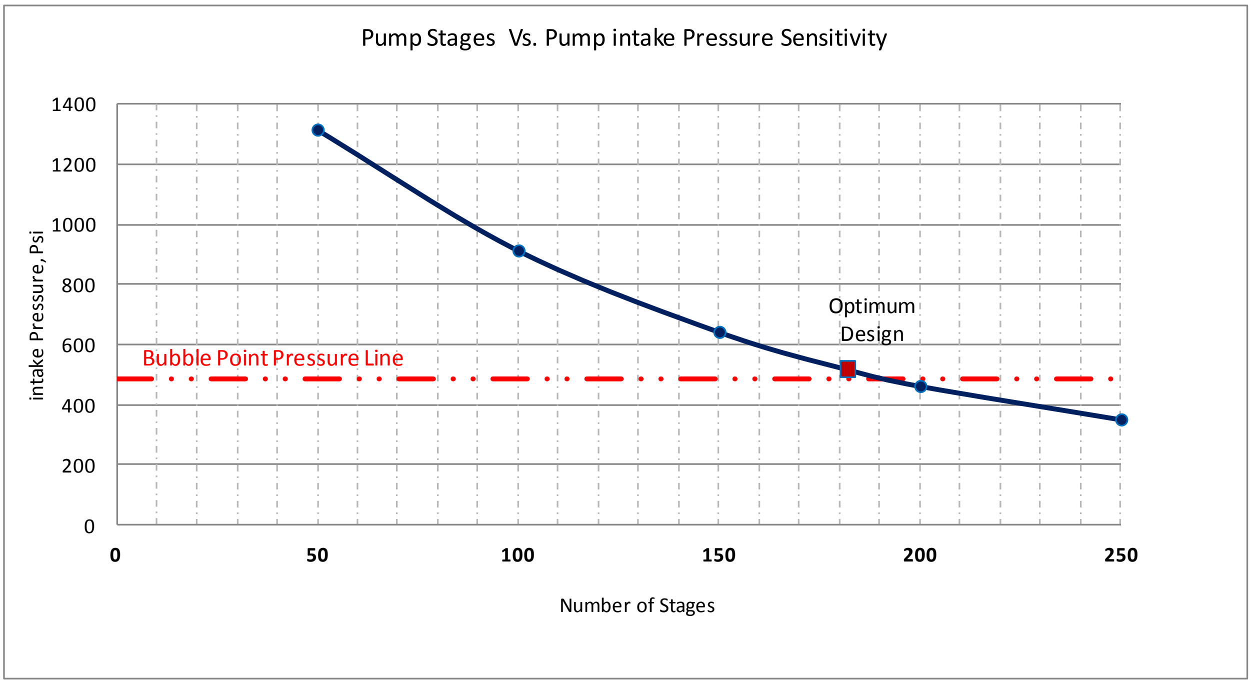

Figure (6-45) Pump intake Pressure Vs Number of stages- well X6, Case 1.

As a comparison between the current case and case 1 for all wells, it was obvious that we could produce the same amount of liquid with less number of stages needed, less horsepower required and with an improvement in pump intake pressure; Table **(6-41)** shows these results.

Wells	Number of Pump stages saved	Enhancement in pump intake pressure, psi
X-1	48	177
X-2	14	265
X-3	30	152
X-4	106	434
X-5	211	637
X-6	-----	60

Table (6-41) shows incremental pump stages saved and incremental increase in pump intake pressure between current Case and Case 1.

- **Water Cut (WC) sensitivity**

It is well known that increased water cut will result increasing in pressure losses in the well and decline in production rate until the well is die, therefore water cut sensitivity analysis in this study provides more information about the wells behavior and how is ESPs performance will change at the two different scenarios.

In X-1 well, as the water cut increases from 60% to 95% Case 1 shows reduction in liquid rate by 38% while in case 2 the reduction is only 12%, **Table (6-42)**. The pump efficiency showed also the same trend for both cases. in Case 1 the pump must be changed at WC 90% because the liquid rate will be outside the optimal pump operating range ,**Figure (6-46) & Figure (6-47).**

Water cut ,%	Liquid rate, STB/d Case 1	Liquid rate, STB/d Case 2
60	753	999.7
70	689	967
80	601	932
85	547	912
90	500	893
95	466	875

Table (6-42) Water cut sensitivity results, well X1.

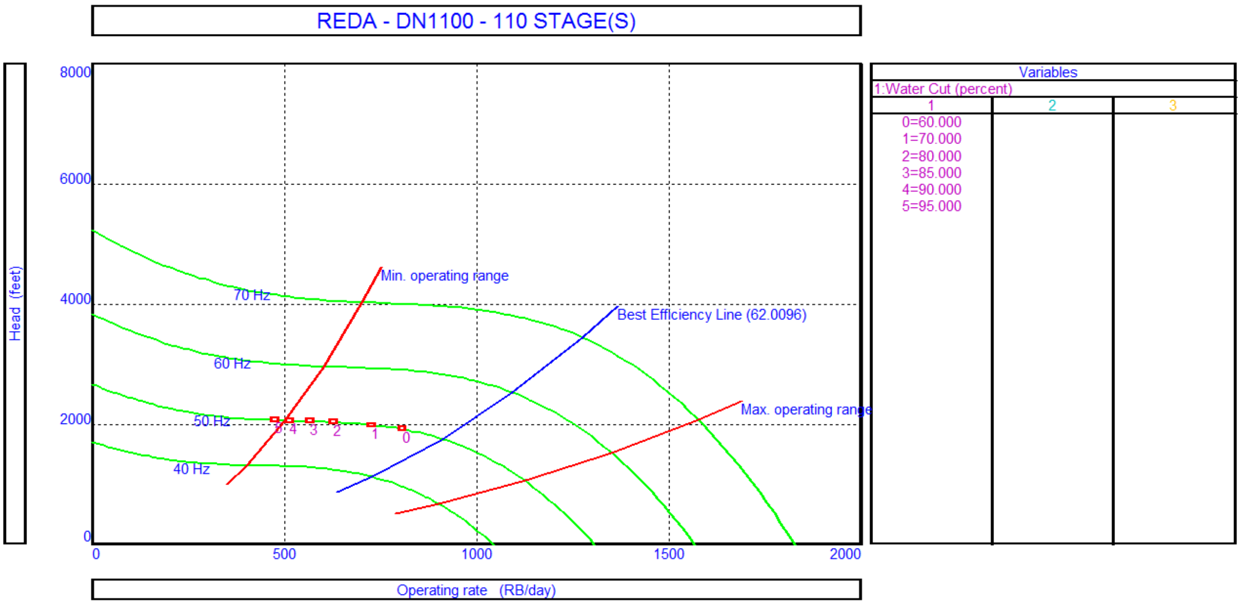

Figure (6-46) Pump Performance Plot at different WC percentage for well X1, Case1.

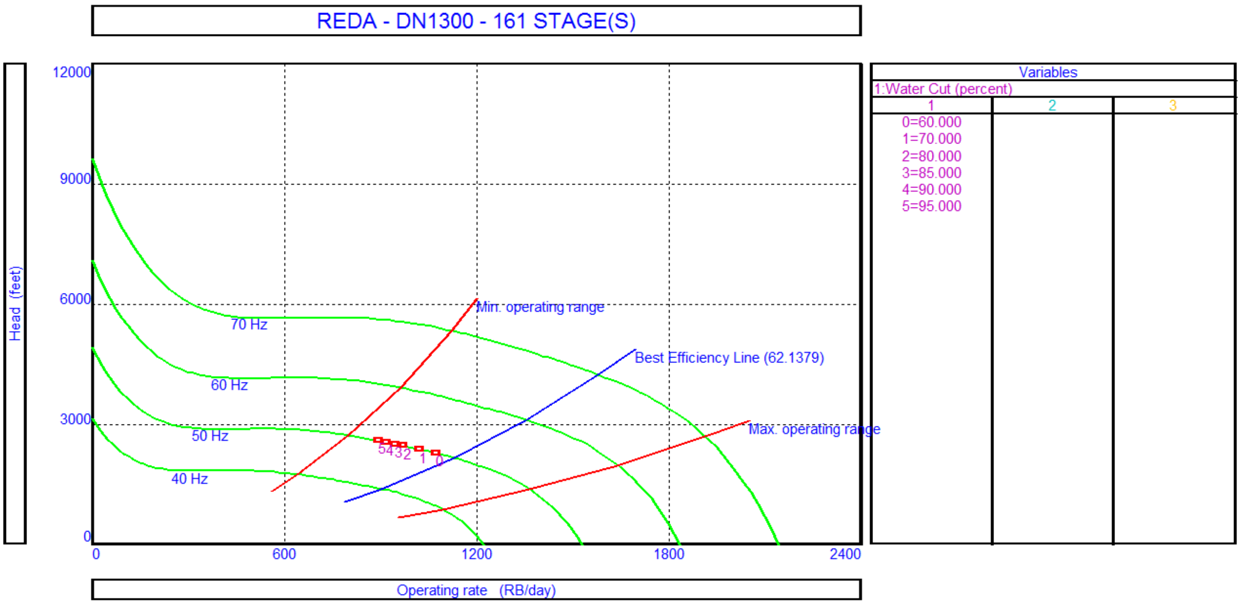

Figure (6-47) Pump Performance Plot at different WC percentage for well X1, Case2.

In X-2 well, as the water cut increases from 60% to 95% Case 1 showed lessening in liquid rate by 9.2% whereas in Case 2 the reduction was only by 3.2%, regarding the pump efficiency Case2 was also less effected by WC increasing, or in other words it did not change, **Table (6-43)** ,**Figure (6-48) & Figure (6-49).**

Water cut ,%	Liquid rate, STB/d Case 1	Liquid rate, STB/d Case 2
60	874	1501
70	851	1487
80	828	1473
85	817	1466
90	805	1459
95	793	1452

Table (6-43) Water cut sensitivity results, well X2.

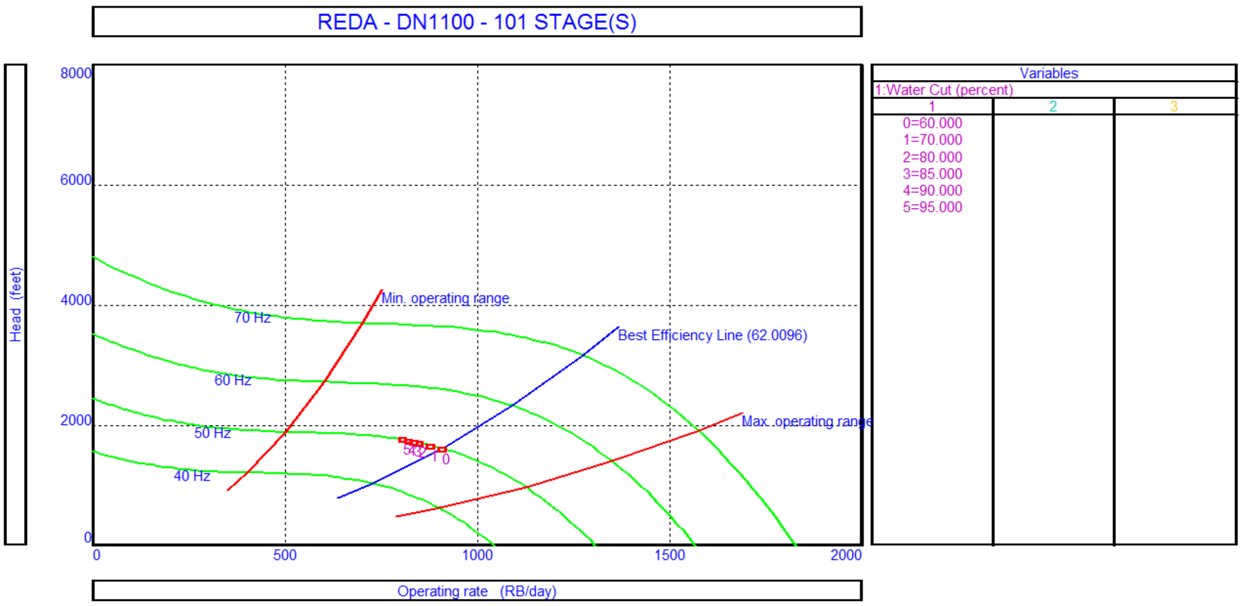

Figure (6-48) Pump Performance Plot at different WC percentage for well X2, Case1.

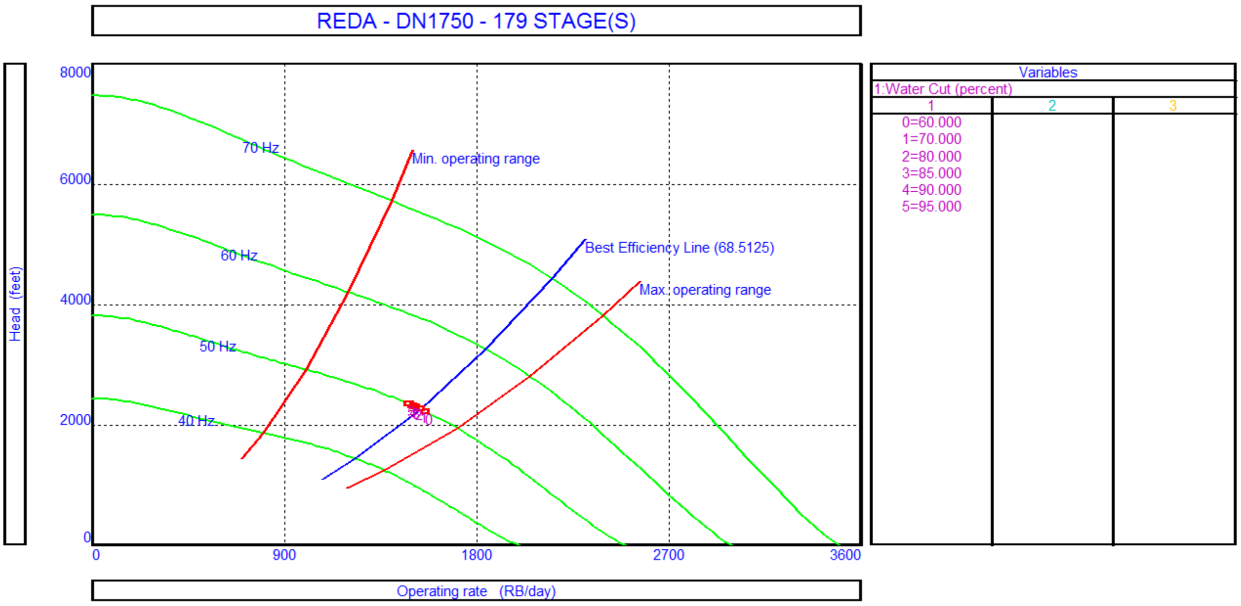

Figure (6-49) Pump Performance Plot at different WC percentage for well X2, Case2.

In X-3 well, as the water cut increases from 50% to 95% case 1 presented reduction in liquid rate by 10% whereas in case 2 the reduction was just by 5%, concerning pump efficiency ,both cases did not change a lot and both still work inside the recommended operating range of pumps, **Table (6-44)** , **Figure (6-50) & Figure (6-51).**

Water cut ,%	Liquid rate, STB/d Case 1	Liquid rate, STB/d Case 2
50	500.8	651
60	489	643
70	477	635
80	465	627
85	461	622
90	456	618
95	451	615

Table (6-44) Water cut sensitivity results, well X3.

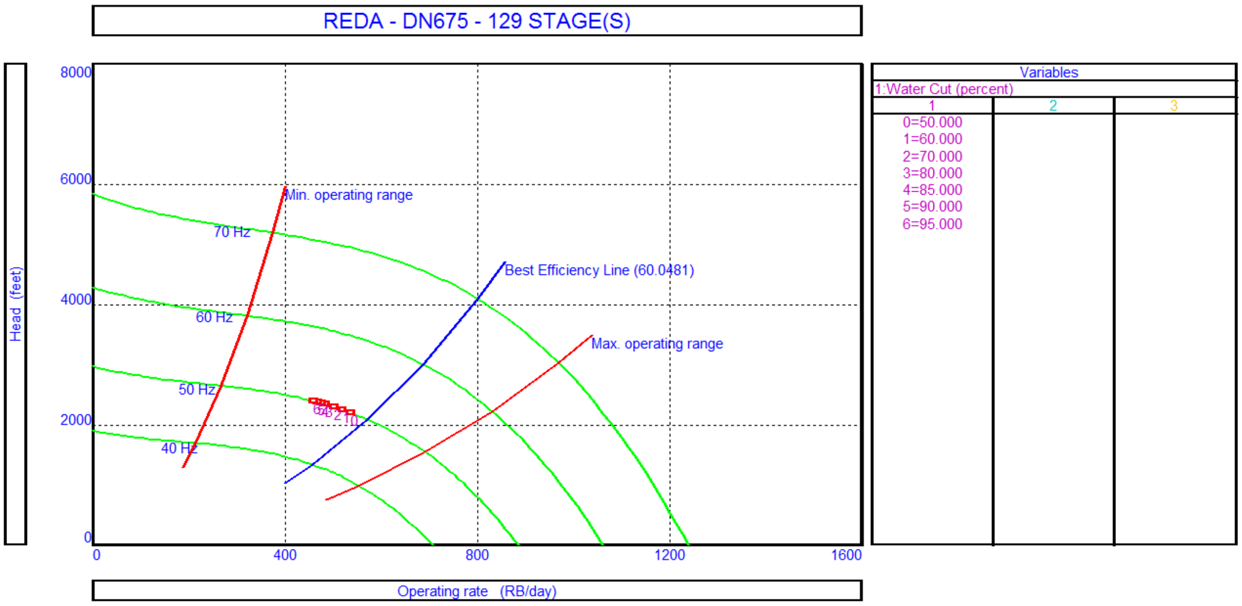

Figure (6-50) Pump Performance Plot at different WC percentage for well X3, Case1.

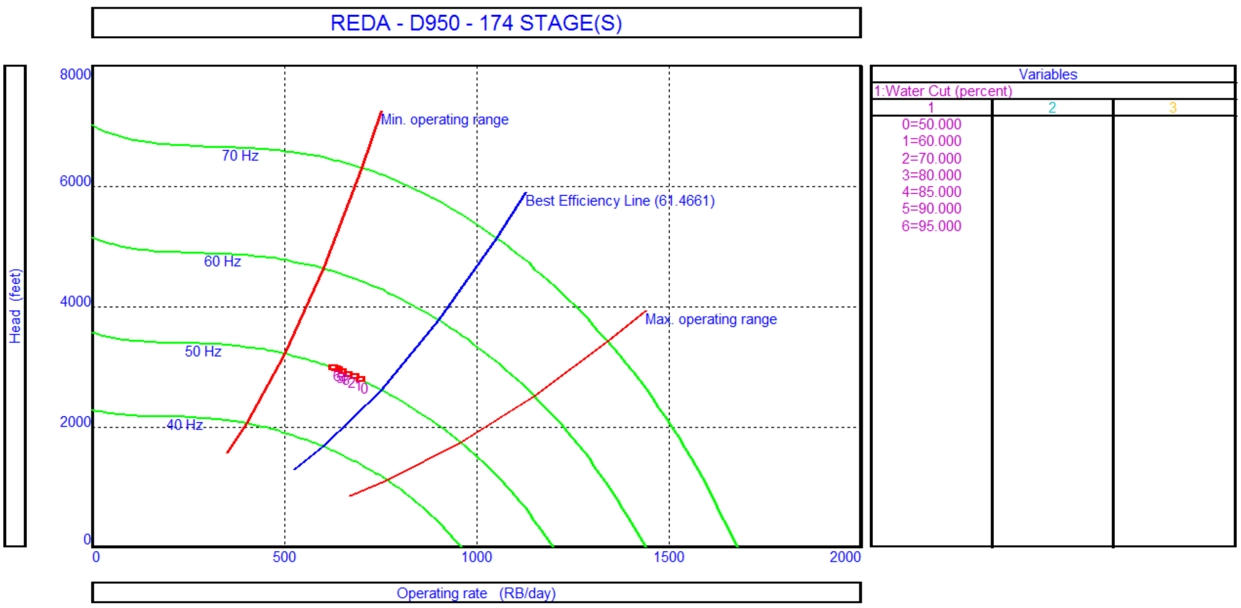

Figure (6-51) Pump Performance Plot at different WC percentage for well X3, Case2.

In X-4 well, as the water cut increases from 40% to 95% case 1 indicated a decline in liquid rate by 27% while in case 2 the reduction is just by 5%. The pump efficiency showed a decline from 61 % to 52% for Case 1 whereas the reduction was about 1 % at WC (95%) for Case2, **Table (6-45)**, **Figure (6-52) & Figure (6-53).**

Water cut ,%	Liquid rate, STB/d Case 1	Liquid rate, STB/d Case 2
40	815	1402
50	792	1388
60	765	1374
70	723	1360
80	677	1345
85	654	1337
90	625	1330
95	597	1325

Table (6-45) Water cut sensitivity results, well X4.

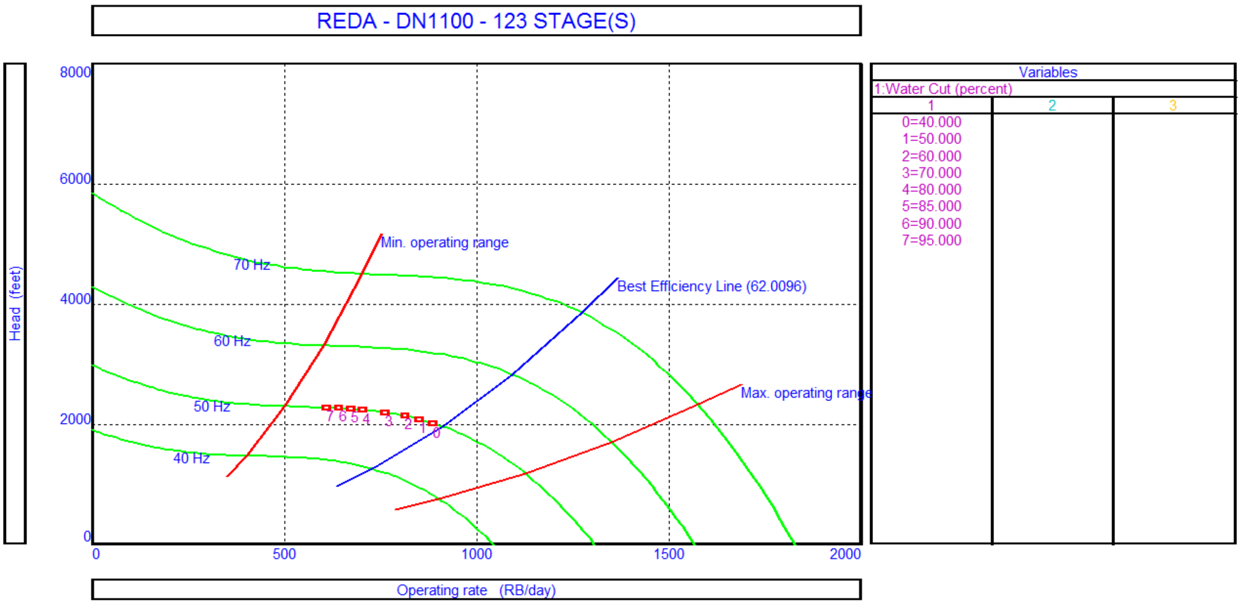

Figure (6-52) Pump Performance Plot at different WC percentage for well X4, Case1.

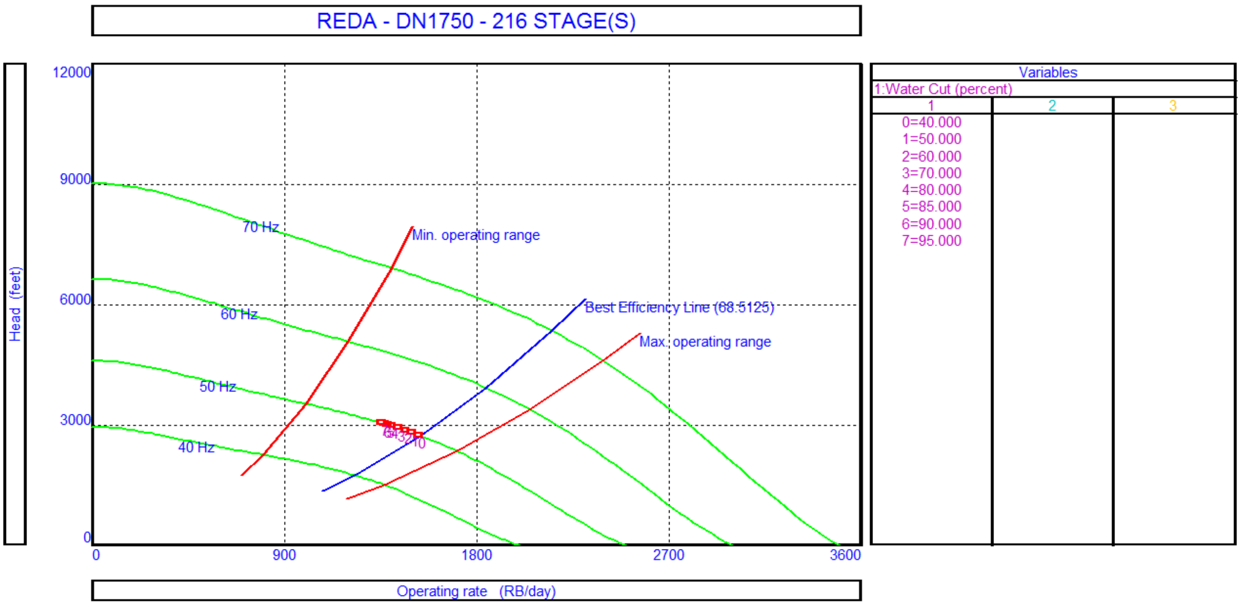

Figure (6-53) Pump Performance Plot at different WC percentage for well X4, Case2.

In X-5 well, as the water cut increases from 25% to 95% case 1 showed a decline in liquid rate by 60% while in case 2 the reduction was just by 21%. Case 1 offers a decrease in pump efficiency from 54.5 % at 25% WC to 33.8% at 95% WC. In Case 2, the range of reduction was narrow since WC equal 25% the efficiency was 52.5% and when WC reaches 95% the pump will work with 48.3% efficiency, **Table (6-46)**, **Figure (6-54) & Figure (6-55).**

Water cut ,%	Liquid rate, STB/d Case 1	Liquid rate, STB/d Case 2
25	251	400.7
30	235	394
40	199	381.8
50	178	369
60	159	354.5
70	142	338.8
80	125	329.5
85	117	325
90	109	321
95	100	317

Table (6-46) Water cut sensitivity results, well X5.

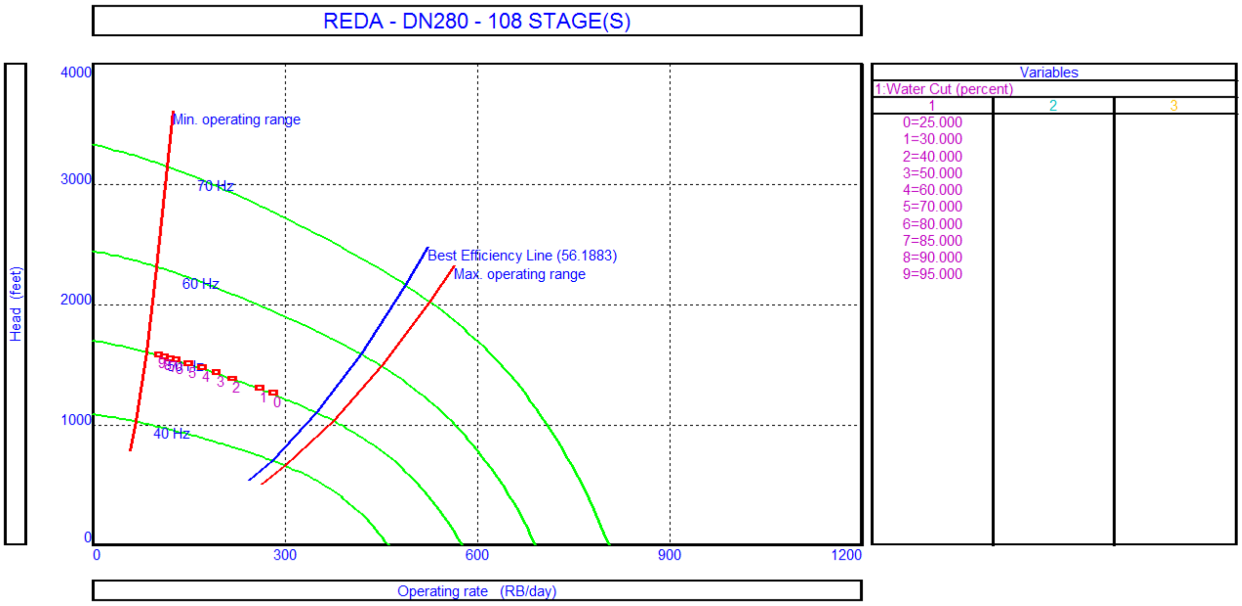

Figure (6-54) Pump Performance Plot at different WC percentage for well X5, Case1.

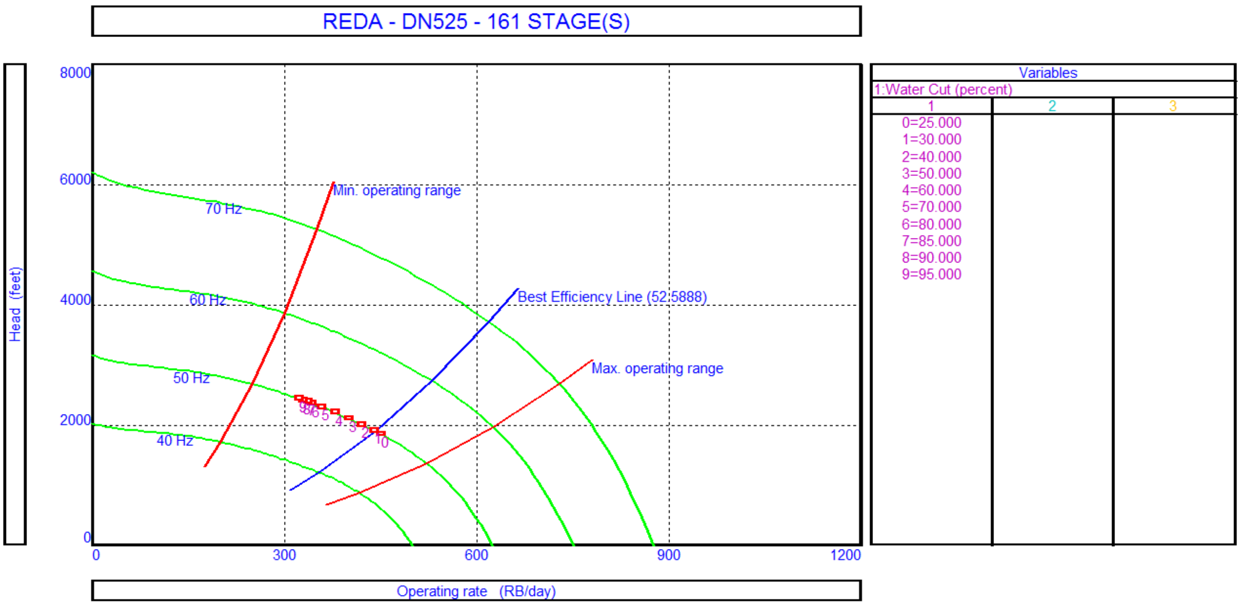

Figure (6-55) Pump Performance Plot at different WC percentage for well X5, Case2.

In X-6 well, as the water cut increases from 65% to 95% the liquid rate shows tiny decline by 1.5%. The same behavior was observed in pump efficiency; nearly did not change, **Table (6-47)**, **and Figure (6-56).**

Water cut ,%	Liquid rate, STB/d Case 1
65	366.1
70	365.2
80	363.5
85	362.6
90	361.8
95	361

Table (6-47) Water cut sensitivity results, well X6.

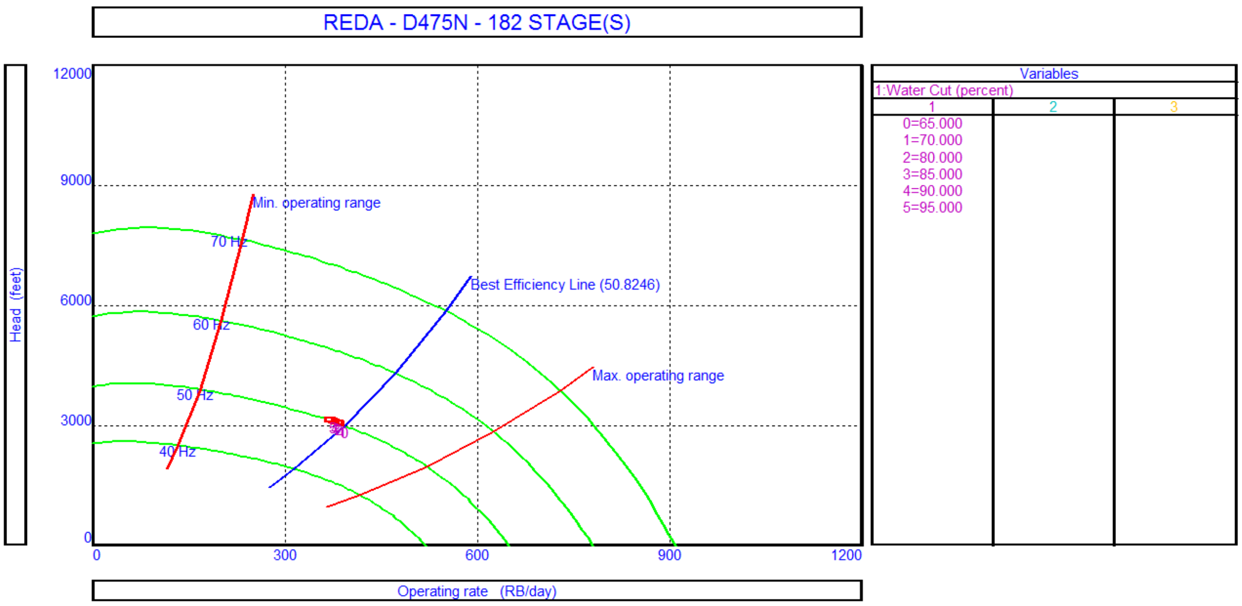

Figure (6-56) Pump Performance Plot at different WC percentage for well X6, Case1.

6.9 Economic Evaluation

The economic calculations are based on three price scenarios, 100 $/bbl, 115 $/bbl and 115 $/bbl. The operating expenses is estimated to be 5 $/bbl (dollar for each barrel produced) while the cost of ESP equipments replacement is applied each three years. The workover job done to change ESP is about 60,000 $. The applied discount rate is assumed to be 10% and Net Cash Flow will be the operating costs plus capital expenditures extracted from total gross revenue. The time period of the analysis is 9 years and the production rate is given to have an exponential production decline curve at a decline rate 0.0536 %/year. It is significance to state that price of equipments used in this study is based on Libyan price market and due to confidential reasons details of equipments price was not included in the thesis.

6.9.1 Current case economic calculations:

The following tables represent the calculation results of the Net Present Value (cumulative discounted net cash flow) at the three price scenarios suggested for the current case.

year	Oil production rate, STB/d	Annual production rate, STB/Year	Oil price ,$	Gross revenue,$	Operating costs $	Capital Expenditure $	Net Cash Flow $	Discounted Net Cash Flow $
1						508,643	**- 508,643**	**-484,972**
2	1710	624,077	100	62,407,700	3,120,385		59,287,315	51,389,306
3	1621	607,792	100	60,779,207	3,038,960		57,740,247	45,498,484
4	1536	576,072	100	57,607,211	2,880,361	508,643	54,218,207	38,839,243
5	1456	546,008	100	54,600,757	2,730,038		51,870,719	33,779,653
6	1380	517,512	100	51,751,206	2,587,560		49,163,646	29,106,120
7	1308	490,504	100	49,050,371	2,452,519	508,643	46,089,209	24,805,433
8	1240	464,905	100	46,490,488	2,324,524		44,165,964	21,609,393
9	1175	440,642	100	44,064,204	2,203,210		41,860,993	18,619,658
10	1114	417,645	100	41,764,544	2,088,227	508,643	39,167,674	15,837,888
TOTAL							**443,055,332**	**279,000,206**

Table (6-48) represent net present value calculation for current case at 100 $/bbl.

year	Oil production rate, STB/d	Annual production rate, STB/Year	Oil price, $	Gross revenue,$	Operating costs $	Capital Expenditure $	Net Cash Flow $	Discounted Net Cash Flow $
1						508,643	**-508,643**	**-484,972**
2	1710	624,077	115	71,768,855	3,120,385		68,648,470	59,503,407
3	1621	607,792	115	69,896,088	3,038,960		66,857,128	52,682,455
4	1536	576,072	115	66,248,292	2,880,361	508,643	62,859,289	45,029,286
5	1456	546,008	115	62,790,870	2,730,038		60,060,832	39,113,282
6	1380	517,512	115	59,513,887	2,587,560		56,926,327	33,701,823
7	1308	490,504	115	56,407,926	2,452,519	508,643	53,446,765	28,765,304
8	1240	464,905	115	53,464,062	2,324,524		51,139,537	25,021,403
9	1175	440,642	115	50,673,834	2,203,210		48,470,624	21,559,604
10	1114	417,645	115	48,029,225	2,088,227	508,643	45,432,355	18,371,082
TOTAL							**513,332,685**	**323,262,676**

Table (6-49) represent net present value calculation for current case at 115 $/bbl.

year	Oil production rate, STB/d	Annual production rate, STB/Year	Oil price, $	Gross revenue,$	Operating costs $	Capital Expenditure $	Net Cash Flow $	Discounted Net Cash Flow $
1						508,643	**-508,643**	**-484,972**
2	1710	624,077	120	74,889,240	3,120,385		71,768,855	62,208,108
3	1621	607,792	120	72,935,049	3,038,960		69,896,088	55,077,112
4	1536	576,072	120	69,128,653	2,880,361	508,643	65,739,649	47,092,634
5	1456	546,008	120	65,520,908	2,730,038		62,790,870	40,891,159
6	1380	517,512	120	62,101,448	2,587,560		59,513,887	35,233,724
7	1308	490,504	120	58,860,445	2,452,519	508,643	55,899,283	30,085,261
8	1240	464,905	120	55,788,586	2,324,524		53,464,062	26,158,739
9	1175	440,642	120	52,877,044	2,203,210		50,673,834	22,539,586
10	1114	417,645	120	50,117,452	2,088,227	508,643	47,520,582	19,215,480
TOTAL							**536,758,469**	**338,016,832**

Table (6-50) represent net present value calculation for current case at 120 $/bbl.

6.9.2 Case 1 economic calculations:

The calculations results are represented in **Tables (6-51), (6-52) and (6-53)**.

year	Oil production rate, STB/d	Annual production rate, STB/Year	Oil price, $	Gross revenue,$	Operating costs $	Capital Expenditure $	Net Cash Flow $	Discounted Net Cash Flow $
1						516,645	**-516,645**	**-492,602**
2	1710	624,077	100	62,407,700	3,120,385		59,287,315	51,389,306
3	1621	607,792	100	60,779,207	3,038,960		57,740,247	45,498,484
4	1536	576,072	100	57,607,211	2,880,361	516,645	54,210,205	38,833,510
5	1456	546,008	100	54,600,757	2,730,038		51,870,719	33,779,653
6	1380	517,512	100	51,751,206	2,587,560		49,163,646	29,106,120
7	1308	490,504	100	49,050,371	2,452,519	516,645	46,081,207	24,801,126
8	1240	464,905	100	46,490,488	2,324,524		44,165,964	21,609,393
9	1175	440,642	100	44,064,204	2,203,210		41,860,993	18,619,658
10	1114	417,645	100	41,764,544	2,088,227	516,645	39,159,671	15,834,652
TOTAL							**443,023,322**	**278,979,301**

Table (6-51) represent net present value calculation for current case at 100 $/bbl.

year	Oil production rate, STB/d	Annual production rate, STB/Year	Oil price, $	Gross revenue,$	Operating costs $	Capital Expenditure $	Net Cash Flow $	Discounted Net Cash Flow $
1						516,645	**-516,645**	**-492,602**
2	1710	624,077	115	71,768,855	3,120,385		68,648,470	59,503,407
3	1621	607,792	115	69,896,088	3,038,960		66,857,128	52,682,455
4	1536	576,072	115	66,248,292	2,880,361	516,645	62,851,286	45,023,554
5	1456	546,008	115	62,790,870	2,730,038		60,060,832	39,113,282
6	1380	517,512	115	59,513,887	2,587,560		56,926,327	33,701,823
7	1308	490,504	115	56,407,926	2,452,519	516,645	53,438,762	28,760,997
8	1240	464,905	115	53,464,062	2,324,524		51,139,537	25,021,403
9	1175	440,642	115	50,673,834	2,203,210		48,470,624	21,559,604
10	1114	417,645	115	48,029,225	2,088,227	516,645	45,424,353	18,367,846
TOTAL							**513,300,675**	**323,241,770**

Table (6-52) represent net present value calculation for current case at 115 $/bbl.

year	Oil production rate, STB/d	Annual production rate, STB/Year	Oil price, $	Gross revenue,$	Operating costs $	Capital Expenditure $	Net Cash Flow $	Discounted Net Cash Flow $
1						516,645	**-516,645**	**-492,602**
2	1710	624,077	120	74,889,240	3,120,385		71,768,855	62,208,108
3	1621	607,792	120	72,935,049	3,038,960		69,896,088	55,077,112
4	1536	576,072	120	69,128,653	2,880,361	516,645	65,731,647	47,086,902
5	1456	546,008	120	65,520,908	2,730,038		62,790,870	40,891,159
6	1380	517,512	120	62,101,448	2,587,560		59,513,887	35,233,724
7	1308	490,504	120	58,860,445	2,452,519	516,645	55,891,281	30,080,954
8	1240	464,905	120	55,788,586	2,324,524		53,464,062	26,158,739
9	1175	440,642	120	52,877,044	2,203,210		50,673,834	22,539,586
10	1114	417,645	120	50,117,452	2,088,227	516,645	47,512,580	19,212,244
TOTAL							**536,726,459**	**337,995,927**

Table (6-53) represent net present value calculation for current case at 120 $/bbl.

6.9.3 Case 2 economic calculations:

The calculations results are represented in **Tables (6-54), (6-55) and (6-56)**.

year	Oil production rate, STB/d	Annual production rate, STB/Year	Oil price, $	Gross revenue,$	Operating costs $	Capital Expenditure $	Net Cash Flow $	Discounted Net Cash Flow $
1						541,835	**-541,835**	**-516,619**
2	2593	946,482	100	94,648,150	4,732,408		89,915,743	77,937,542
3	2458	921,784	100	92,178,361	4,608,918		87,569,443	69,003,461
4	2330	873,677	100	87,367,679	4,368,384	541,835	82,457,461	59,068,448
5	2208	828,081	100	82,808,061	4,140,403		78,667,658	51,230,564
6	2093	784,864	100	78,486,404	3,924,320		74,562,084	44,142,636
7	1983	743,903	100	74,390,289	3,719,514	541,835	70,128,940	37,743,730
8	1880	705,079	100	70,507,946	3,525,397		66,982,548	32,773,025
9	1782	668,282	100	66,828,217	3,341,411		63,486,807	28,238,762
10	1689	633,405	100	63,340,530	3,167,027	541,835	59,631,669	24,112,734
TOTAL							**672,860,517**	**423,734,284**

Table (6-54) represent net present value calculation for current case at 100 $/bbl.

year	Oil production rate, STB/d	Annual production rate, STB/Year	Oil price, $	Gross revenue,$	Operating costs $	Capital Expenditure $	Net Cash Flow $	Discounted Net Cash Flow $
1						541,835	**-541,835**	**-516,619**
2	2593	946,482	115	108,845,373	4,732,408		104,112,965	90,243,470
3	2458	921,784	115	106,005,115	4,608,918		101,396,197	79,898,744
4	2330	873,677	115	100,472,831	4,368,384	541,835	95,562,612	68,456,330
5	2208	828,081	115	95,229,270	4,140,403		91,088,867	59,319,600
6	2093	784,864	115	90,259,364	3,924,320		86,335,044	51,112,526
7	1983	743,903	115	85,548,832	3,719,514	541,835	81,287,483	43,749,312
8	1880	705,079	115	81,084,138	3,525,397		77,558,740	37,947,713
9	1782	668,282	115	76,852,450	3,341,411		73,511,039	32,697,514
10	1689	633,405	115	72,841,610	3,167,027	541,835	69,132,749	27,954,602
TOTAL							**779,443,863**	**490,863,194**

Table (6-55) represent net present value calculation for current case at 115 $/bbl.

year	Oil production rate, STB/d	Annual production rate, STB/Year	Oil price, $	Gross revenue,$	Operating costs $	Capital Expenditure $	Net Cash Flow $	Discounted Net Cash Flow $
1						541,835	**-541,835**	**-516,619**
2	2593	946,482	120	113,577,780	4,732,408		108,845,373	94,345,446
3	2458	921,784	120	110,614,033	4,608,918		106,005,115	83,530,506
4	2330	873,677	120	104,841,215	4,368,384	541,835	99,930,996	71,585,625
5	2208	828,081	120	99,369,673	4,140,403		95,229,270	62,015,946
6	2093	784,864	120	94,183,684	3,924,320		90,259,364	53,435,823
7	1983	743,903	120	89,268,347	3,719,514	541,835	85,006,998	45,751,172
8	1880	705,079	120	84,609,535	3,525,397		81,084,138	39,672,609
9	1782	668,282	120	80,193,861	3,341,411		76,852,450	34,183,765
10	1689	633,405	120	76,008,636	3,167,027	541,835	72,299,775	29,235,225
TOTAL							**814,971,644**	**513,239,497**

Table (6-56) represents net present value calculation for current case at 120 $/bbl.

According to the previous results, there was a slight difference in the Cumulative Net cash flow and Net Present Value(NPV) between the current case and the first case .As an example ,the incremental increase in Net present value between the current case and the first case at 100$/bbl is about 20,905 $ as well as in the second scenario at 115 $/bbl and in the third one at 120 $/bbl. on the other hand , a noticeable increase in the NPV comparing the current and the second case reaches about 52%.**Figures (6-57), (6-58) and (6-59)**.

For PayOut time indicator, it is obvious that for all cases the money disbursed will be recovered since the beginning of production.

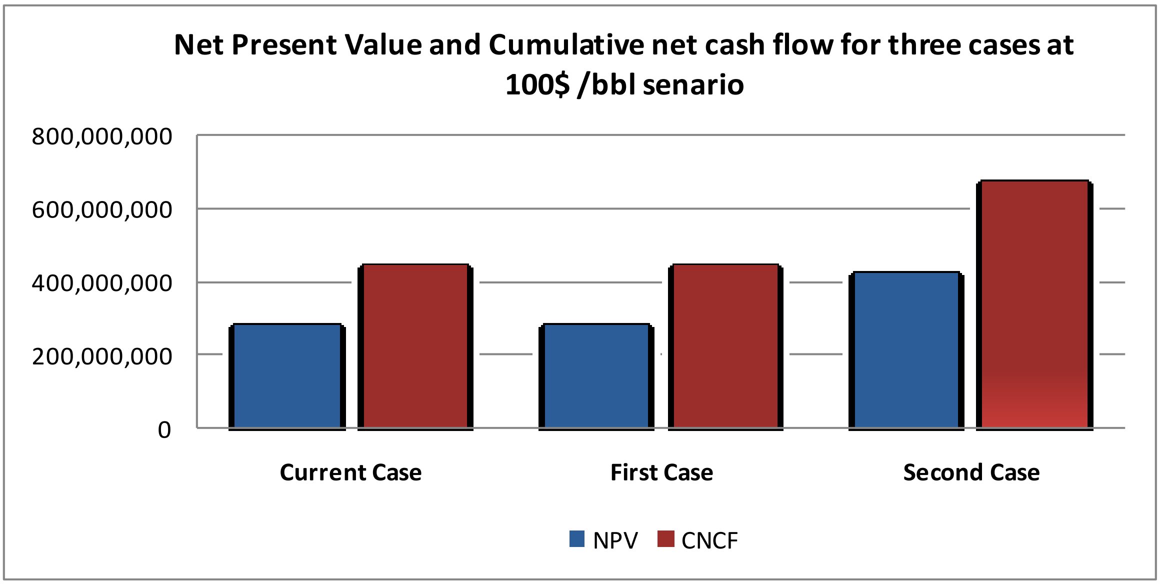

Figure (6-57) Comparison between economic indicators for three cases at 100$/bbl.

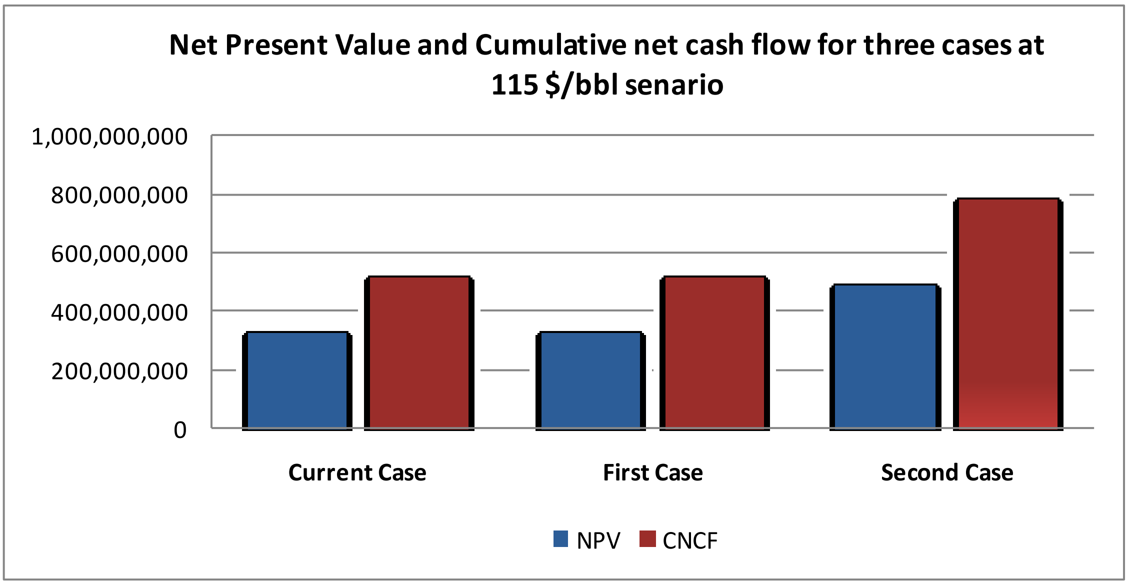

Figure (6-58) Comparison between economic indicators for three cases at 115 $/bbl.

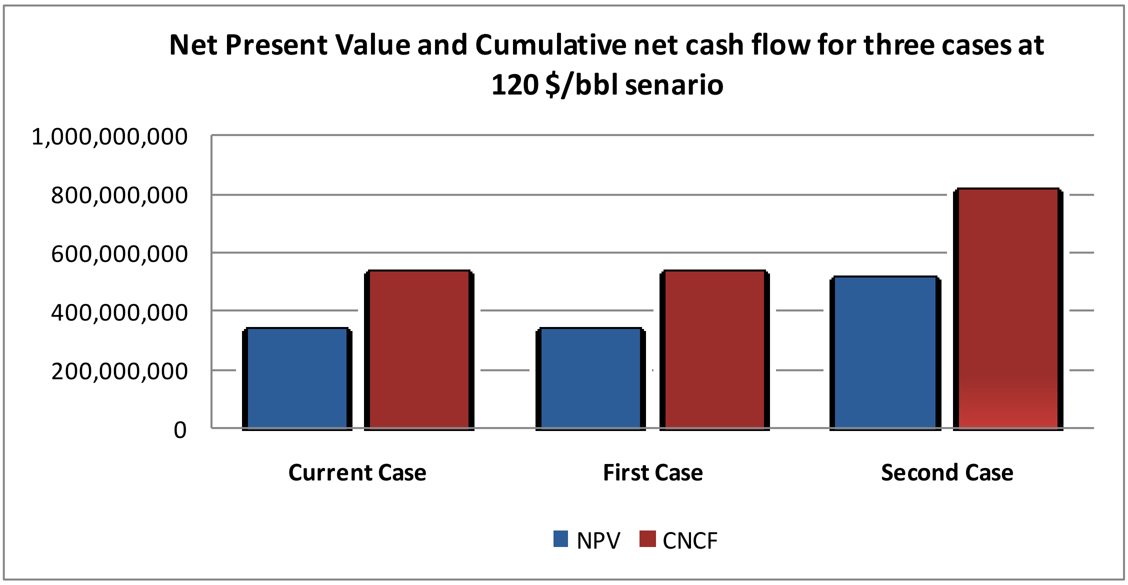

Figure (6-59) Comparison between economic indicators for three cases at 120 $/bbl.

CHAPTER 7

Conclusions and Recommendations

Understanding the current operating conditions for ESP lifted wells helps engineers to choose the best production optimization technique. As well as the proper electric submersible pump (ESP) design in oil wells can result in improved production performance and extended pump life. In addition to that running sensitivity analysis procedure will improve the available choices of ESP operating equipments such as pumps, motors and cables.

Modifying the pump setting depth as necessary gave the opportunity to avoid gas lock problems in the selected wells.

The 6 wells under study operated at lower efficiency than they should be also the current pumps used have number of stages more than necessary and as a result more horsepower is required. Although the first case showed a reduction in number of stages and improvement in pump efficiency, the second case offered higher design liquid rate with higher pump efficiency. Because of that the economic evaluation was necessary to assess the situation and present the best choice between cases. By applying the well known profit indicators, the second case which represents optimizing new ESPs at high liquid rate expressed the best decision and higher profits alternative among the three cases.

During the analysis, PROSPER software offers using conventional speed drive unit for the electric motor which limits the electrical frequency options. It is recommended to use variable speed drive system in order to convert the input frequency into any frequency in pump operating range and gives more flexibility for the optimization process.

In order to decrease the total dynamic head produced and enhance the study results, the combined ESP with gas lift technology could be utilized. It is recommended also to include the surface components when applying the nodal analysis approach to get more accurate results.

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