بسم الله الرحمن الرحيم

Sudan University of Science and Technology
College of Petroleum Engineering and Mining

Project Title:

Production System Optimization by using Electrical Submersible Pump Case Study -Abugabra field-Sudan

تحسين نظام الانتاج باستخدام المضخة الكهربائية الغاطسة-تطبيق في حقل ابوجابرة في السودان

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قال تعالي:

(مَا كَانَ لِبَشَرٍ أَن يُؤْتِيَهُ اللَّهُ الْكِتَابَ وَالْحُكْمَ وَالنُّبُوَّةَ ثُمَّ يَقُولَ لِلنَّاسِ كُونُوا عِبَادًا لِّي مِن دُونِ اللَّهِ وَلَٰكِن كُونُوا رَبَّانِيِّينَ بِمَا كُنتُمْ تُعَلِّمُونَ الْكِتَابَ وَبِمَا كُنتُمْ تَدْرُسُونَ)

صدق اللّه العظيم

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Dedication

Every challenging work needs self-efforts as well as guidance of elders especially those were very close to our heart our humble effort we dedicate to our sweet and loving parents those affection ,love and encouragement make us able to get much success and honor along with hard working and respected teachers

Acknowledgments

First and foremost, thanks of allah for the gift of life in good health and abundant grace throughout our stay in this great citadel. It is indeed a privilege and honor to pass through this great college.

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Special thank to our families for patience and assistance over the years

ABSTRACT

During the reservoir production life reservoir pressure will decline. Also after water breakthrough the fluid column weight will increase as hydrostatic pressure will increase because of increased water and oil mixture density. In this case, reservoir pressure may not be enough to lift up the fluid from bottom to the surface. These reasons decrease or even may cause to stop flowing of fluids from the well. Some techniques must be applied to prevent the production decline.A small change in water cut gives a large change in oil production. This study uses a simulated model of the PIPESIM artificial lift method based on the operating limits of the electrical submersible pump artificial lift technique applied to the *MOGA* well and *SUF3* at the Abu GAbra field in Sudan. The results from the advanced simulation model show that the ESP solution gives a production rate ranging from (0-799.98 STB/D) a pump type (REDA D1050N 140 stages, 2916.7 RPM, 50 Hz) for a *MOGA* well and a production rate ranging from (0- 1500.202 STB/D) a pump type (REDA DN 1800 737 stages, 2916.7 RPM, 50 Hz) for a *SUF3* well.

التجريد

خلال فترة إنتاج الخزان سينخفض ضغط الخزان. أيضًا بعد اختراق الماء ، سيزداد وزن عمود المائع مع زيادة الضغط الهيدروستاتيكي بسبب زيادة كثافة خليط الماء والزيت. في هذه الحالة ، قد لا يكون ضغط الخزان كافيًا لرفع السائل من الأسفل إلى السطح. تتناقص هذه الأسباب أو قد تتسبب في توقف تدفق السوائل من البئر. يجب تطبيق بعض التقنيات لمنع انخفاض الإنتاج ، فالتغيير البسيط في قطع المياه يؤدي إلى تغيير كبير في إنتاج الزيت. تستخدم هذه الدراسة نموذج محاكاة لطريقة الرفع الاصطناعي PIPESIM بناءً على حدود التشغيل لتقنية الرفع الاصطناعي للمضخة الغاطسة الكهربائية المطبقة على بئر MOGA و SUF3 في حقل أبو جابرة في السودان. تظهر النتائج من نموذج المحاكاة المتقدم أن حل ESP يعطي معدل إنتاج يتراوح من (0-799.98 STB / D) نوع مضخة (REDA 140 D1050N، 2916.7 RPM، 50 Hz) لبئر MOGA ومعدل إنتاج يتراوح من (0- 1500.202 STB / D) نوع مضخة (REDA DN 1800737 مراحل ، 2916.7 دورة في الدقيقة ، 50 هرتز) لبئر SUF3.

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List of Abbreviations

ESP	Electrical Submersible Pump
HZ	Hertz
OD	Outside Diameter
VLP	Vetical Lift Performance
PIP	Pump Intake Pressure
PI	Productivity Index
PR	Reservoir Pressure
PWF	Flowing Bottom Hole Pressure
Q	Flow Rate
QMAX	Maximum Flow Rate
IPR	Inflow Performance Relationships
API	Oil Gravity
GOR	Gas Oil Ratio
PNODE	Pressure On Node
PSEP	Pressure In Separator

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Chapter 1

Introduction

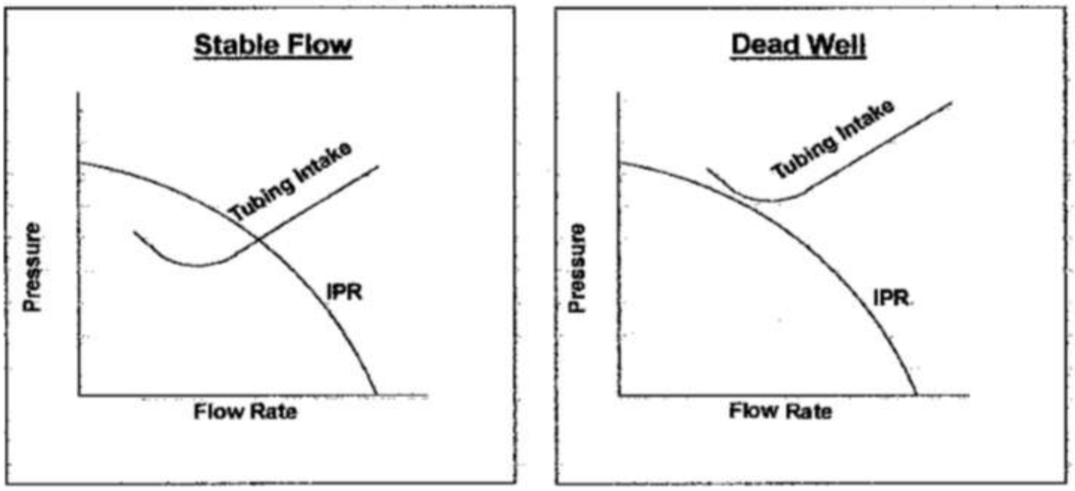
1.1 General Introduction:

Usually, oil wells in early stages of their lives flow naturally to the surface and are called flowing wells. Flowing production means that the pressure at the well bottom is sufficient to overcome the sum of pressure losses occurring along the flow path to the separator. When this criterion is not met, natural flow ends and the well die. The two main reasons of a well's dying are:

1. The flowing buttomhole pressure drops below the total pressure losses in the well
2. Pressure losses in the well become greater than the bottom hole pressure needed for moving the well stream to the surface

To overcome these problems, artificial lift methods can be used to assist wells to sustain flow of oil to surface at adequate rates. Artificial lift enable 'dead well' to flow by adding energy to fluid stream and reducing fluid gradient below the reservoir sand face pressure. (Gabor Takacs, 2009)

Figure (1: 1): The IPR Curve for Stable and Dead Well (Gabor Takacs, 2009)



One widely used type of artificial lift method uses a pump set below the liquid level as to increase the pressure and to overcome the pressure losses occurring along the flow path such as electrical submersible pump (ESP). Other lifting methods use gas injected from the surface into the well tubing to help lifting of well fluids to the surface. But in this research, it will more focus on electrical submersible pump, operating features and design ESP system for given case study.

As for the early history part, ESP was invented and developed by a Russian named Aramis Arutunoff in the late 1910's. Arutunoff make his first experiments in the Baku oil fields near the Caspian Sea and was later the founder of the company Russian Electrical Dynamo of Arutunoff (RED A).

From the early days, ESP units have excelled in lifting much greater liquid rates than most of the other types of artificial lift and have found their best use in high-rate onshore and offshore applications. High gas production, quickly changing liquid production rates, viscous crudes and various conditions once very detrimental to ESP operations are now easily handled by present-day units. And it is believed that today approximately 10% of the world's oil supply is produced with submersible pumping installations. (Gabor Takacs, 2009)

1.2 Problem Statement:

The increase in the water cut in Moga and *Suf3* wells of the reservoir that produces natural production and also the lack of effective support for the reservoir pressure commensurate with the amount of oil produced from the reservoir caused the reservoir to be depleted and stopped Two wells, which caused a decrease in the production capacity of the reservoir, thus resorting to an Electric submersible pump design is necessary.

1.3Objectives:

The objective of this study is to perform a production engineering study at Abu GAbra Oil field in Sudan. The main goal of the study is to achieve production optimization of Two electrical submersible pump lifted wells currently operating in this field and increase the productivity, by using software program PIPESIM this includes the following:

1. To identify Optimum production rate
2. To identify the optimum pump stages
3. To determine horsepower requirement for a possible production rate
4. To identify the efficiency of pump

Chapter 2

Literature review

2.1 Drive Mechanisms:

According to (Dake2002**)** oil production is due to the following drive mechanisms:

1. Natural water drive
2. Solution gas drive
3. Gas-cap drive
4. Compaction drive

Natural water drive: A drop in the reservoir pressure, due to the production of fluids, causes the aquifer water to expand and flow into the reservoir. 50% of oil recovery can be caused by natural water drive. (Dake2002)

Solution gas drive: When the reservoir pressure drops below the bubble point pressure solution gas dissolved in oil appears as a free phase. When pressure drops further the highly compressible gas expands expelling the oil from porous media.

Gas-cap drive: High gas compressibility and the extended gas cap size ensure a long lasting and efficient field performance. Up to 35% of the original oil in place can be recovered under a gas-cap drive. (Dake2002)

Compaction drive: This drive mechanism might occur during depletion when rock grains are subjected to stress beyond elasticity limit. It leads to a re-compaction of partially deformed or even destroyed rock grains that might result in gradual or abrupt reduction of the reservoir pore volume. In order to achieve better field performance, secondary and tertiary oil recovery methods are often implemented. Gas lift and down hole pumps are examples of advanced recovery techniques Enhanced Oil Recovery, (EOR). (Dake2002)

2.2 Artificial Lift Method:

Artificial lifting methods are used to produce fluids from wells already dead or to increase the production rate from flowing wells. If the producing bottom hole pressure becomes so low that it will not allow the well to produce at a desired flow rate, then some sort of artificial energy supply will be needed to lift the fluid out of the wellbore, Energy can be supplied indirectly by injecting water or gas into the reservoir to maintain reservoir pressure or through a variety of artificial lift methods that are applied at the producing well itself, There are many artificial lift methods, such all are variations or combinations of three basic processes: (Wilson, B. L 2002)

1. Lightening of the fluid column by gas injection (gas lift)
2. Subsurface pumping (beam pumps, hydraulic pumps, electric submersible centrifugal pumps)
3. piston-like displacement of liquid slugs (plunger lift)

Although the use of many of those lifting mechanisms may be restricted or even ruled out by actual field conditions such as well depth, production rates desired, fluid properties and so on, more than one lift system turns out to be technically feasible. It is the production engineer's responsibility to select the type of lift that provides the most profitable way of producing the desired liquid volume from the given wells. After a decision is made concerning the lifting method, a complete design of the installation for initial and future conditions should follow (Wilson, B. L 2002)

2.3. Electrical Submersible Pump Components:

2.3.1 Introduction:

During its long history, the ESP system proved to be an efficient artificial lift selection to produce liquid from the production wells. The ESP unit is run on the tubing string and is submerged in well fluids. The electric submersible motor is at the bottom of the unit and is cooled by the well stream passing by its perimeter (A. Suat Bagci2010**)** It is connected to the seal section that provides many crucial functions for the safe operation of the unit. On top of the protector a pump intake or gas separator is situated which allows well fluids to enter the pump as well as can remove low quantities of free gas from the well stream at the same time. Liquid is lifted to the surface by the centrifugal pump (Wilson, B. L 2002). On the surface equipment, it includes a junction box where down hole and surface electric cables are joined and a control unit that provides measurement and control functions. The ESP unit receives AC electricity from a set of transformers which supply

the required voltage by stepping up or down the voltage available from the surface electric network.

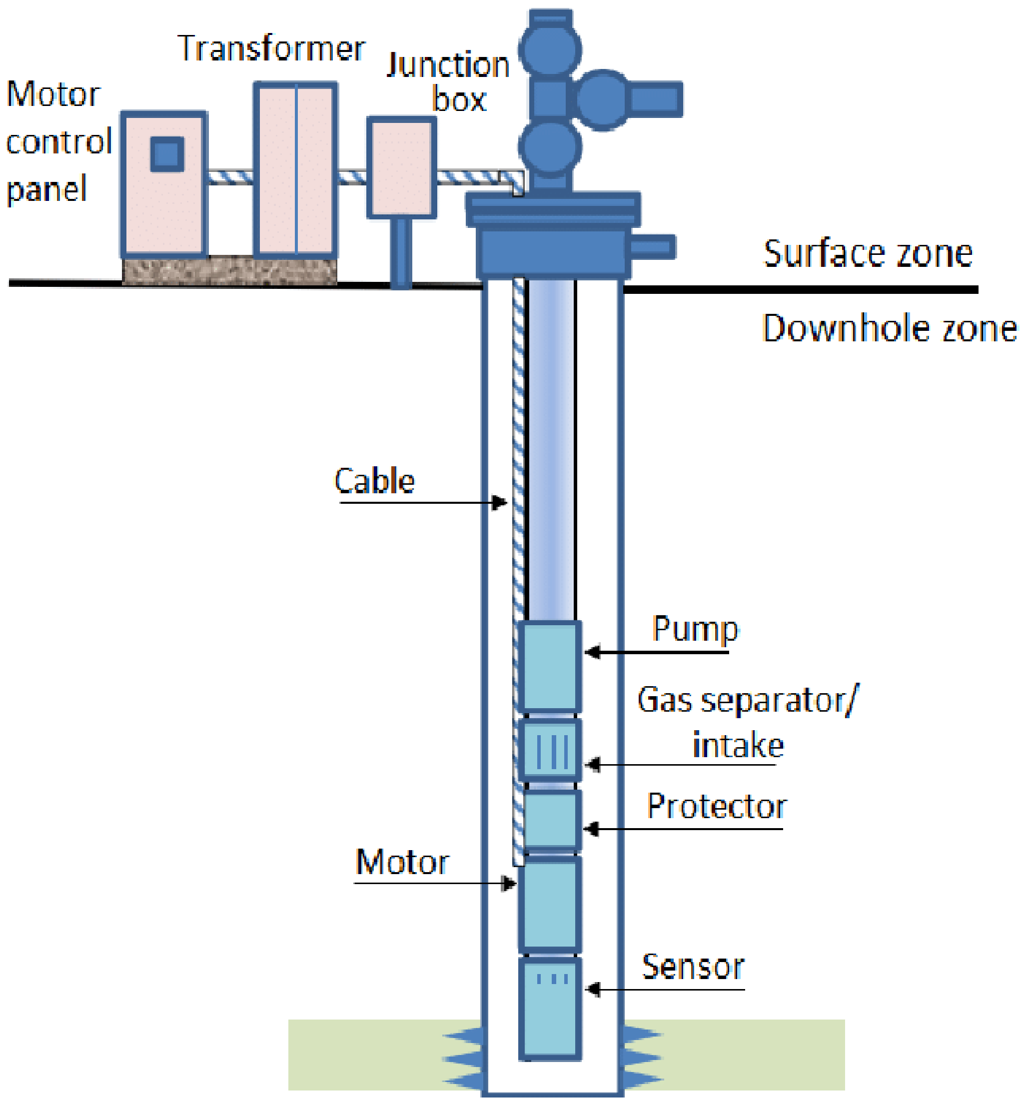


Figure (2.2): ESP System Component (Wilson, B. L 2002)

There are some advantages and disadvantages of ESP itself as follows: (Wilson, B. L 2002)

Advantages:

1. High fluid volume capability33
2. Can be used in high water cut well
3. Can be fitted with down hole pressure sensor (data transmission via power cable)
4. Compatible with crooked or deviated wellbores
5. Corrosion and scale treatments are relatively easy to perform
6. Available in a range of sizes and capacities
7. Lifting cost for high volumes typically very low

Disadvantages:

1. Cable insulation deteriorates in high temperatures (+350°F)
2. System is depth limited (+10,000 ft.) due to cable cost and inability to provide sufficient power
3. Large casing/liners are required (7" above)
4. Entire system is down hole; therefore, problems and maintenance require the unit to be retrieved from the wellbore
5. More detailed engineering required for design

2.3.2 The Submersible Pump:

In ESP unit, the submersible pump is one of important equipment. The design and analysis of the ESP system need the basic comprehension and understanding of the operation of the pump. The submersible pumps used in ESP installations are multistage centrifugal pumps operating in a vertical position and the basic operational principle remained the same. Produced liquids, after being subjected to great centrifugal forces caused by the high rotational speed of the impeller, lose their kinetic energy in the diffuser where a conversion of kinetic to pressure energy takes place**.** (Gabor Takacs2009)

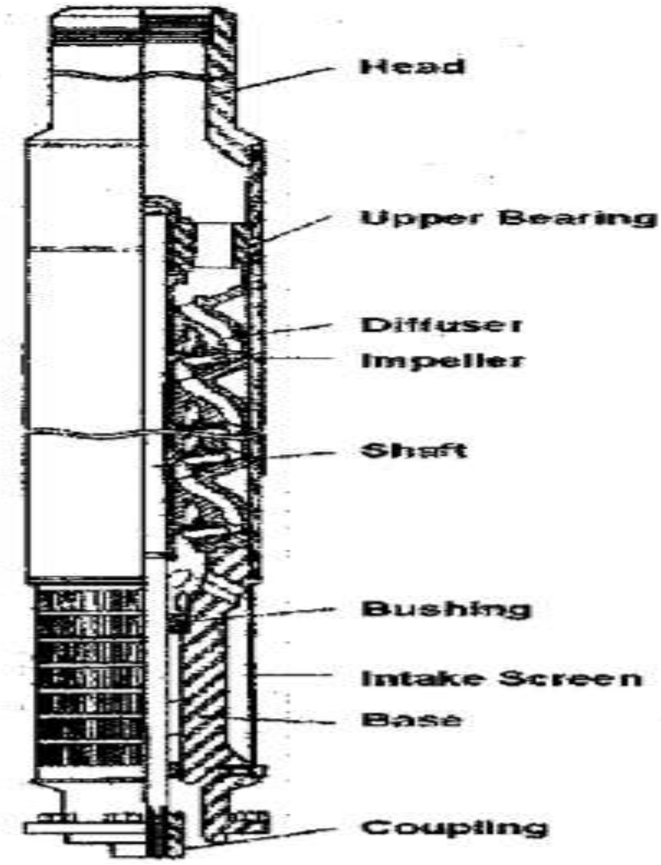


Figure (2.3): Main Parts of an ESP Pump (Gabor Takacs2009)

The figure above shows the main parts of an ESP pump containing mixed-flow stages. 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. (Gabor Takacs2009)

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.

The liquid producing capacity of an ESP pump depends on the following factors:(Gabor Takacs2009)

1. The rotational speed provided by the electric motor
2. The diameter of the impeller
3. The design of the impeller (characterized by its specific speed)
4. The number of stages

5. The actual head against which the pump is operating
6. The thermodynamic properties of the produced fluid. (Density, viscosity)

(Gabor Takacs 2009) The ESP installations will 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, meanwhile in case of a 50 Hz power supply the motor speed is about 2,900 RPM. Usually, 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" up to 11 "

2.3.3 The ESP Motor:

ESP motors are three-phase, two-pole, squirrel cage induction type electric motors. The construction of squirrel cage induction motors is the simplest among electric motors. They are also the most reliable motors due to the fact that their rotor is not connected to the electric supply. At the same time, these motors are the most efficient ones available they are very popular in oilfield applications. (Gabor Takas. 2009)

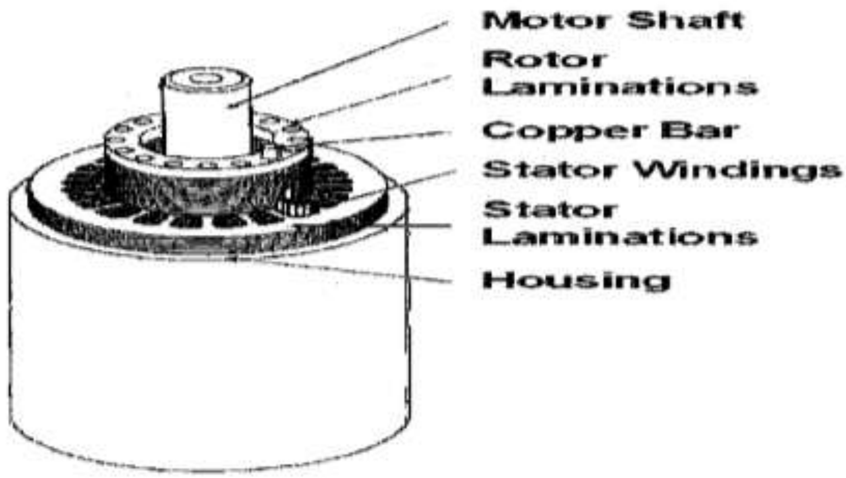


Figure (2.4): Construction details of an ESP motor's stator and rotor (Gabor Takacs2009)

Inside the motor housing and attached to it is the stator, a hollow cylinder made up of a great number of tightly packed thin steel discs called laminations. Stator laminations prevent the creation of wasteful eddy currents in the metal body of the stator. They have several "slots" accommodating the insulated copper stator windings connected to the AC power (Gabor Taka's 2009) There are three pairs of coils displaced at 120° along the perimeter of the motor and connected to one of each electric phase. The two coils of each pair are wound facing each other on opposite sides of the stator.

Inside the stator and separated from it by an annular "air gap" is the rotor, consisting of rotor laminations containing in their slots a set of copper bars. These are joined at their ends by so-called "end rings" (copper washers), making up the "squirrel cage". (Wilson, B. L)

The rotating magnetic field developed by the AC current flowing in the stator windings induces a current in the rotor. Due to this induced current a magnetic field develops in the rotor. The interaction of the two magnetic fields turns the rotor and drives the motor shaft firmly attached to the rotor.

To prevent electrical failures in windings, the motor must have a sophisticated insulation system including:

1. Insulation of the individual wires making up the windings
2. Insulation between the windings and the stator
3. Protection against phase to phase faults

Windings in ESP motors, just like m other electric motors, are encapsulated with an insulating material to:

1. improve the dielectric strength of winding insulation,
2. improve the mechanical strength of windings and eliminate wire movement,
3. protect wires and end coils from contaminants.

2.3.3.1 Operational Features:

ESP motors are very different from electric motors in everyday use on the surface. The most important differences are listed in the following, a basic comprehension of which is necessary to fully understand the operational features of ESP motors. (Sun, D. - Prado, 2003)

1. Since they must be run inside the well's casing string, their length to diameter ratio is much greater than that of surface motors.

2. Motor power can only be increased by increasing the length of the unit.
3. Surface motors are usually cooled by the surrounding air whereas ESP motors are cooled by the convective heat transfer taking place in the well fluid flowing past the motor.
4. Because of the great difference between the heat capacities of air and liquids and the accordingly higher cooling effect, electric current densities more than ten times higher than those in surface motors can be used in ESP motors without severe overheating.
5. ESP motors have exceptionally low inertia and accelerate to full speed in less than 0.2 seconds when starting.
6. ESP motors are connected to their power source by long well cables, where a substantial voltage drop can occur.

2.3.4 The Seal Protection:

In small or non-industrial submersible pumps, the electric motor is completely sealed against the produced liquid so as to prevent short-circuits and burning of the motor after it is contaminated with well fluids. Since the motor must be filled up with high dielectric strength oil, ESP motors operating at elevated temperatures, if completely sealed, would burst their housing due to the great internal pressure developed by the expansion of the oil. This is the reason why ESP motors must be kept open to their surroundings but at the same time must still be protected from the harmful effects of well fluids. This is provided by connecting a seal section or protector between the motor and the centrifugal pump. (A. Suat Bagci2010)

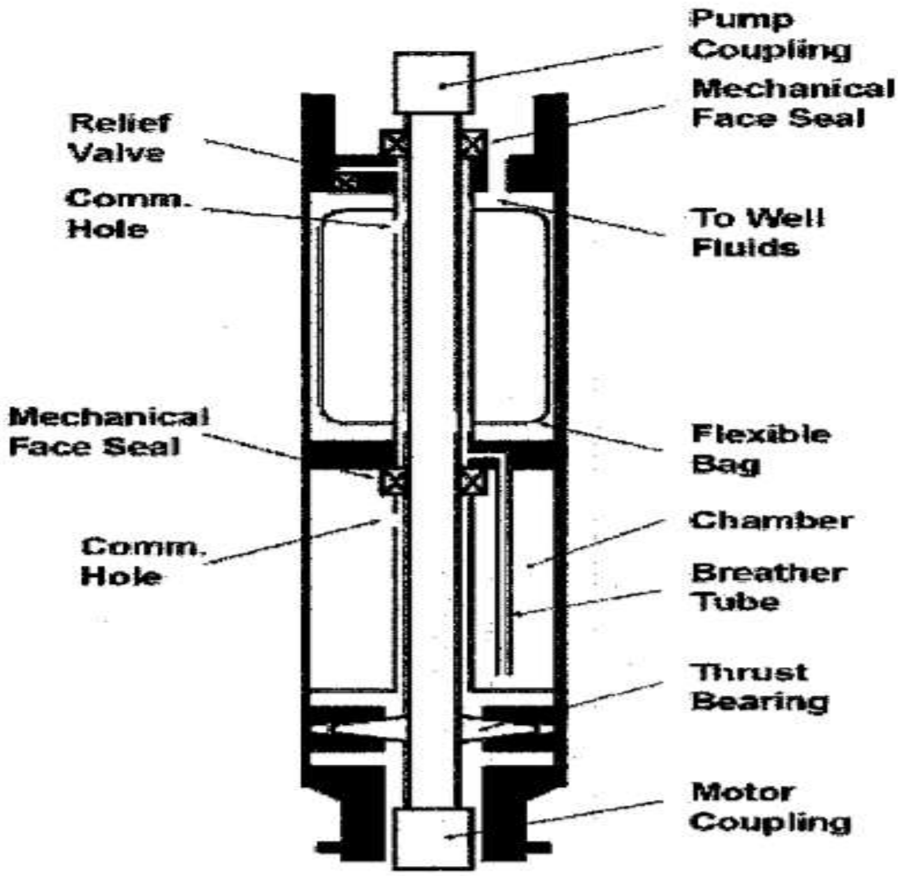


Figure (2.5): Schematic Drawing of an ESP Seal Section (A. Suat Bagci2010)

An ESP protector performs the following five very crucial functions and in so doing ensures the proper operation of the whole installation:

1. . It ensures that no axial thrust load developing in the ESP pump's stages during operation is transmitted to the motor shaft. Thrust loads transmitted to the pump shaft are supported by the protector that contains the ESP unit's main thrust bearing. This thrust bearing must be capable to overcome the net axial force acting on the pump shaft.
2. . The protector isolates the clean dielectric oil with which the motor is originally filled up from well fluids that are usually loaded with dirt, water and other impurities. It must ensure that no well fluid enters the motor during operation. This is a basic requirement because contamination of the clean motor oil can cause premature motor failures due to

• The loss of lubrication in the structural bearings and the consequently increased wear in bearing surfaces.

• The decrease of the electrical insulation strength of the motor oil causing short circuits in the motor's stator or rotor windings.

3. . It allows for the expansion and contraction of the high quality oil the motor is filled up with. Since the protector is connected directly to the motor, motor oil expanding due to well temperature and due to the heat generated in the motor can enter the protector during normal operation. Similarly, during shutdowns, the oil contained in the motor shrinks because of the decreased motor temperature and part of it previously stored in the protector can be sucked back to the motor space.
4. . By providing communication between well fluids and the dielectric oil contained in the motor, the protector equalizes the inside pressure with the surrounding pressure in the well's annulus. Inside and outside pressures being approximately equal, leakage of well fluids past the sealed joints and into the motor is eliminated. This feature

   • allows the use of low-pressure and consequently lower cost seals.

   • Greatly increases the reliability of the ESP system.

5. . It provides the mechanical connection between the motor and the ESP pump and transmits the torque developed by the motor to the pump shaft. The couplings on the protector's shaft ends must be capable to transmit not only the normal operating torques but the much greater torques occurring during system startup. (A**.** Suat Bagci2010)

2.3.5 The Gas Separator:

It follows from the operational principle of centrifugal pumps that free gas entering the pump suction deteriorates the pump's performance. This is caused by the great difference between the specific gravities of liquids and gases. The centrifugal pump imparts a high rotational velocity on the fluid entering its impeller but the amount of kinetic energy passed on to the fluid greatly depends on the given fluid's density. Liquid receives a great amount of kinetic energy that, after conversion in the pump stage, increases the pressure. Gas cannot produce the same amount of pressure increase. This is the reason why centrifugal pumps should always be fed by gas-free, single phase liquid for ensuring reliable (A. Suat Bagci2010)

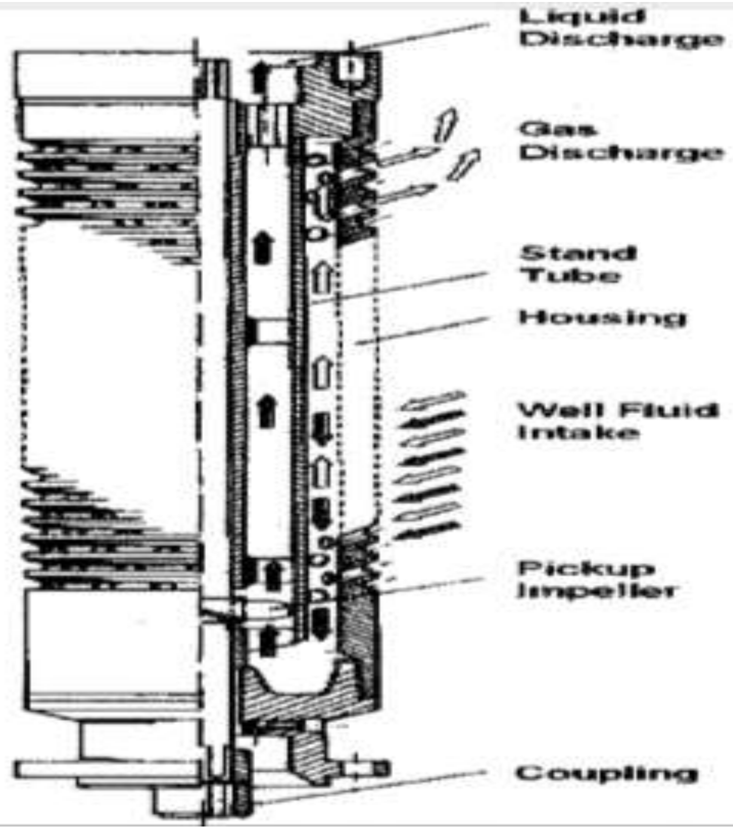


Figure (2.6): Construction of Gas Separator (A. Suat Bagci2010)

The existence of free gas at pump suction conditions affects the operation of the ESP pump is several ways.

1. The head developed by the pump decreases as compared to the performance curve measured with water
2. The output of a pump producing gassy fluids fluctuates; cavitation's can also occur at higher flow rates causing mechanical damage of the pump stages
3. In cases with extremely high gas production rates, gas locking may occur when no pumping action is done by the pump completely filled with gas

2.4 Well Inflow Performance:

2.4.1 Introduction:

The proper design of any artificial lift system requires a good and accurate knowledge of the fluid rates that can be produced from the reservoir. Present and also future production rates are needed to accomplish the following basic tasks of production engineering: (Michael Golan and others 1985)

1. Selection of the right type of lift
2. Detailed design of production equipment
3. Estimation of future well performance

Therefore, the production engineer must have a clear understanding of the effects governing fluid inflow into a well. Lack of information may lead to over-design of production equipment or equipment limitations may restrict attainable liquid rates. Both of these conditions have an undesirable impact on the economy of artificial lifting and can be the cause of improper decisions as well. (Michael Golan and others 1985)

2.4.2 The Productivity Index Concept:

The simplest approach to describe the inflow performance of oil wells is the use of the productivity index (PI) concept. It was developed using the following assumptions:

1. Flow is radial around the well
2. A single phase and incompressible liquid
3. Permeability in the formation is homogeneous
4. The formation is fully saturated with the given liquid

$PI = \frac{Q}{Pr-Pwf}$ $(EQ1)$……………………………………………… (Michael Golan and others 1985)

The equation states that liquid inflow into a well is directly proportional to pressure drawdown, as plotted in the graph below. The use of the PI concept is straightforward. If the average reservoir pressure and the productivity index are known, use of the equation gives the flow rate for any flowing bottom hole pressure. The well's PI can either be calculated from reservoir parameters or measured by taking flow rates at various Pwf

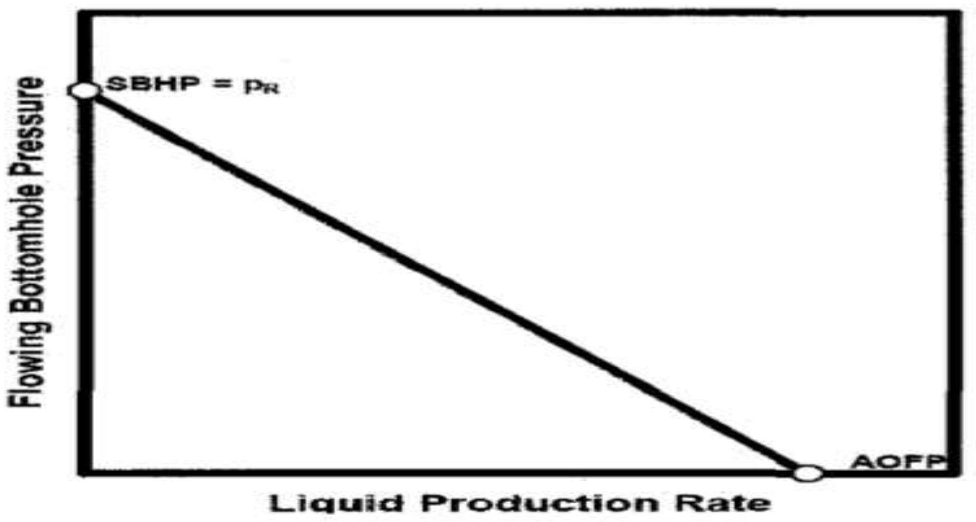


Figure (2: 7): Well Inflow Performance with the PI Constant *(*Michael Golan andothers1985*)*

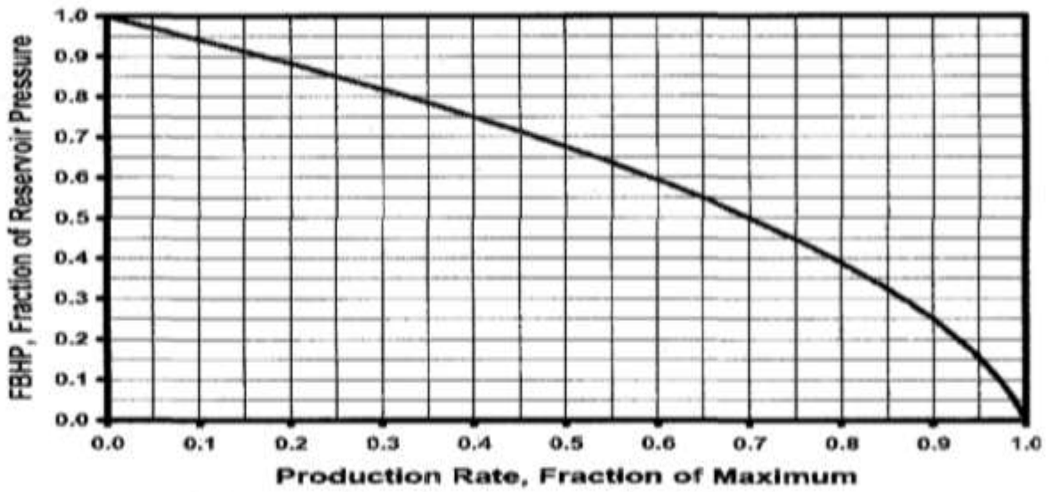
2.4.3 Inflow Performance Relationships:

In many wells on artificial lift, bottom hole pressures below bubble point pressure are experienced. There is a free gas phase present in the reservoir near the wellbore and the assumptions that were used to develop the PI equation are no longer valid.

The main cause of a curved shape of inflow performance is the liberation of solution gas due to the decreased pressure in the vicinity of the wellbore. This effect creates an increasing gas saturation profile toward the well and simultaneously decreases the effective permeability to liquid. Liquid rate is accordingly decreased in comparison to single-phase conditions and the well produces less liquid than indicated by a straight-line PI curve. Therefore, the constant PI concept cannot be used for wells producing below the bubble-point pressure.

2.4.3.1 Vogel's IPR Correlation:

Vogel used a numerical reservoir simulator to study the inflow performance of wells depleting solution gas drive reservoirs. He considered cases below bubble-point pressure and varied pressure drawdown’s, fluid and rock properties. After running several combinations on the computer, Vogel found that all the calculated IPR curves exhibited the same general shape. The shape is approximated by a dimensionless equation as follows:



$\frac{Q}{Qmax} = 1 - 0.2\left[\frac{Pwf}{Pr}\right] - 0.8\left[\frac{Pwf}{Pr}\right]^2 \quad (EQ2)$.................. (Gaviara, F., Santos 2007)

Figure (2: 8): Vogel's Dimensionless IPR Curve (Gaviara, F., Santos 2007)

2.5 Nodal Analysis Approach:

The systems analysis approach, often called NODAL Analysis, has been applied for many years to analyze the performance of systems composed of interacting components. Electrical circuits, complex pipeline networks and centrifugal pumping systems are all analyzed using this method. Its application to well producing systems was first proposed by (Gilbert in 1954) and discussed by (Nind in 1964) and (Brown in 1978). The production system can be relatively simple or can include many components in which energy or pressure losses occur. Figure (9) illustrates a number of the components in which pressure losses occur. The procedure consists of selecting a division point or node in the well and dividing the system at this point. All of the components upstream of the node comprise the inflow section, while the outflow section consists of all of the components downstream of the node. A relationship between flow rate and pressure drop must be available for each component in the system. The flow rate through the system can be determined once the following requirements are satisfied (Beggs 1991):

is the average reservoir pressure, $\overleftarrow{Pr}$ and the other is the system outlet pressure. The outlet pressure is usually the separator pressure, $Psep$, but if the well is controlled by a surface choke the fixed outlet pressure may be the wellhead pressure Pwh.

Once the node is selected, the node pressure is calculated from both directions starting at the fixed pressures

1. Flow into the node equals flow out of the node
2. Only one pressure can exist at a node.

At a particular time in the life of the well, there are always two pressures that remain fixed and are not functions of flow rate. One of these pressures

Inflow to the node:

$\overleftarrow{Pr}\ - \Delta P$(Upstream components) = $Pnode$…………………………..(Beggs 1991)

Outflow from the node:

$Psep\ + \Delta$P(downstream component) = $Pnode$…………………….(Beggs 1991)

The pressure dropΔP, in any component varies with flow rate$Q$. Therefore, a plot of node pressure versus flow rate will produce two curves, the intersection of which will give the conditions satisfying requirements 1 and 2, given previously. The effect of a change in any of the components can be analyzed by recalculating the node pressure versus flow rate using the new characteristics of the component that was changed. If a change was made in an upstream

component, the outflow curve will remain unchanged. However, if either curve is changed, the intersection will be shifted, and a new flow capacity and node pressure will exist. The curves will also be shifted if either of the fixed pressures is changed, which may occur with depletion or a change in separation conditions. Figure (10) illustrates the comparison of intake curves for artificial lift methods. It can be observed from the figure that electrical submersible

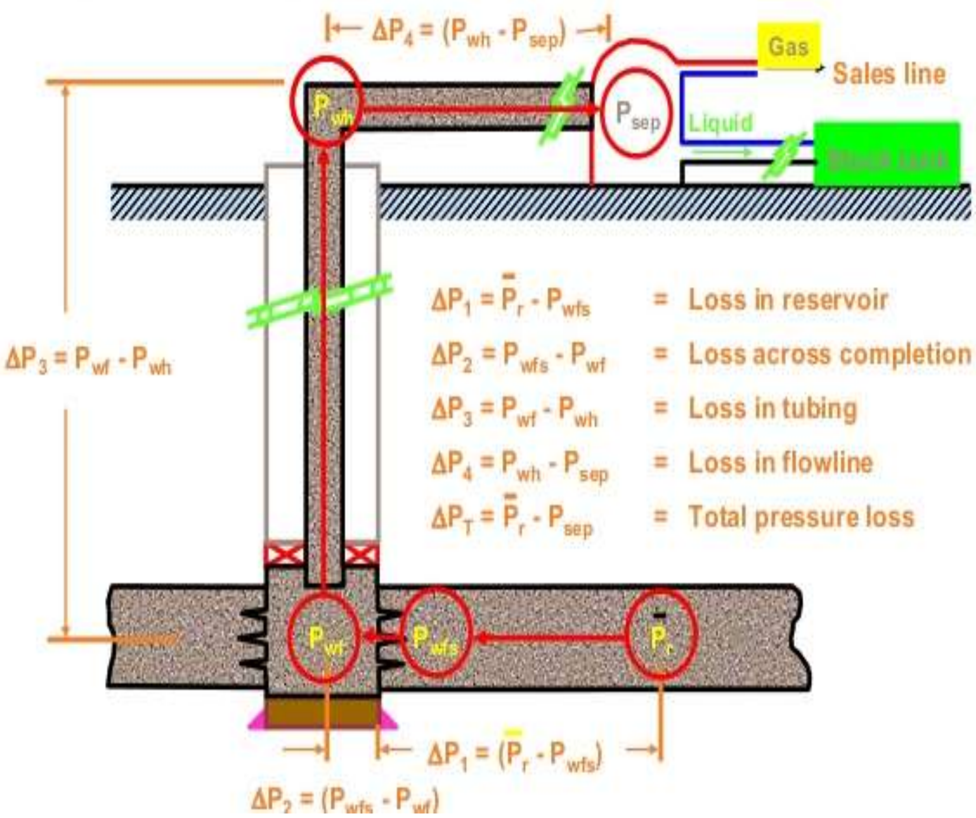


Figure (2.9) Pressure Losses in a Production System (Beggs1991)

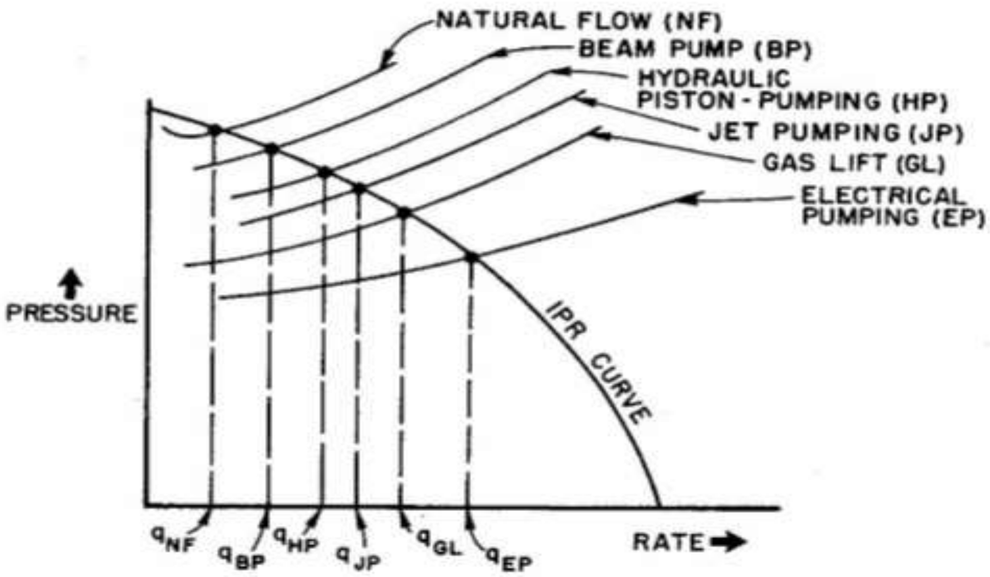


Figure (2.10): Tubing Intake Curves for Artificial Lift System (Brown, K. E1984)

The nodal systems analysis approach may have used to analyze many producing oil and gas well problems. The procedure can be applied to both flowing and artificial lift wells, if the effect of artificial lift method on the pressure can be expressed as a function of flow rate. The procedure can also be applied to the analysis of injection well performance by appropriate modification of the inflow and outflow expressions. A partial list of possible applications is given as follows (Beggs in 1991):

1. Selecting tubing size
2. Selecting flow line size
3. Gravel pack design
4. Surface choke sizing
5. Subsurface safety valve sizing
6. Analyzing an existing system for abnormal flow restrictions
7. Artificial lift design
8. Well stimulation evaluation
9. Determining the effect of compression on gas well performance
10. Analyzing the effects of perforating density
11. Predicting the effect of depletion on producing capacity
12. Allocating injection gas among gas lift wells
13. Analyzing a multiwell producing system
14. Relating field performance to time

Chapter 3

METHEDOLOGY

3.1Review of Software PIPESIM:

PIPESIM is built & innovated by Schlumberger (Schlumberger2012), it's a way use to simulate individual well and network models. PIPESIM combines best-in-class science with an unparalleled productivity environment to enable engineers to optimize production systems from the reservoir to the sales point. These release notes describe the most significant enhancements and known limitations.

The conditions of the well allows you to select suitable Electrical Submersible Pump (ESP) from the database and performs necessary calculations to determine the number of stages required to achieve target flow rate under given well, fluid and operating conditions. Multiple operations are performed as part of well's ESP design to calculate and report well performance before and after an ESP is installed. PIPESIM is primarily configured to perform single ESP Design and pump selection. However, you may design and select pumps in tandem by performing successive design steps.

3.2 Steps of Design

3.2.1Data Required

1. Well Data
2. Fluid Properties
3. Production Data
4. Additional Data

WELL DATA

WELL NAME	Tubing OD; (lb./ft.)	Casing OD; (lb./ft.)	Pump Setting Depth, (m)	Top of Perforations, (mkb)	Static Bottom Hole Temp, (deg C)	Surface Wellhead Temp, (deg C)	Primary Power Frequency, (Hz)	Deviated/Vertical Well
Moga	3 1/2"	7" @ 1998mk	1500.0	1511	68	35	50	Vertical
Suf3	3 1/2"	9-5/8" @ 3800mk	3200	3441	75	35	50	Vertical

Table (3.1)

Fluid Properties

Well Name	Oil Gravity, (deg API)	Water Cut (% water)	Gas Oil Ratio (GOR), scf/bbl
Moga	35.0	0	199
Suf3	31	10	100

Table (3.2)

Production Data

Well Name	Current Reservoir Pressure, (Psi)	Productivity Index (Pi),(Blpd/Psi)	Desired Tubing Pressure, (Psi)
Moga	1800	1.00	200
Suf3	3000	1.00	300

Table (3.3)

Additional Data

WELL NAME	A) POINT 1, TEMP_50C, CP	B) POINT 2, TEMP_45C, CP
Moga	13.0	24.0
Suf3	13.0	24.0

Table (3.4)

3.2.2Steps of Software

First steps

1. Well is completely defined with all the components and properties are required.
2. One or more fluid models are defined and each completion of a well is mapped to a fluid.

Second steps

1. Click ESP design from the Tasks in a Well-centric workspace. In Network-centric mode, select the well and then click ESP Design to open the ESP Design Task.
2. Under Boundary Conditions, specify all the required data. Specify Design Criteria. Desired tubing pressure (200psi for *Moga* well and 300psi for *Suf3*) were used. And 1500m and 3200 pump setting depth added for *Moga* and *Suf3* respectively.
3. Click ... under pump selection group to open pump selection menu, View/specify pump filtering option to control pump list under display, Select a suitable pump from the pump selection table according to the maximum efficiency , optimum production rate and performance pump curve. And click OK to exit pump selection window and go back to the task window.
4. Click Run.

   Results tab displays once run is performed to populate the results.

Chapter 4

Results and Discussions

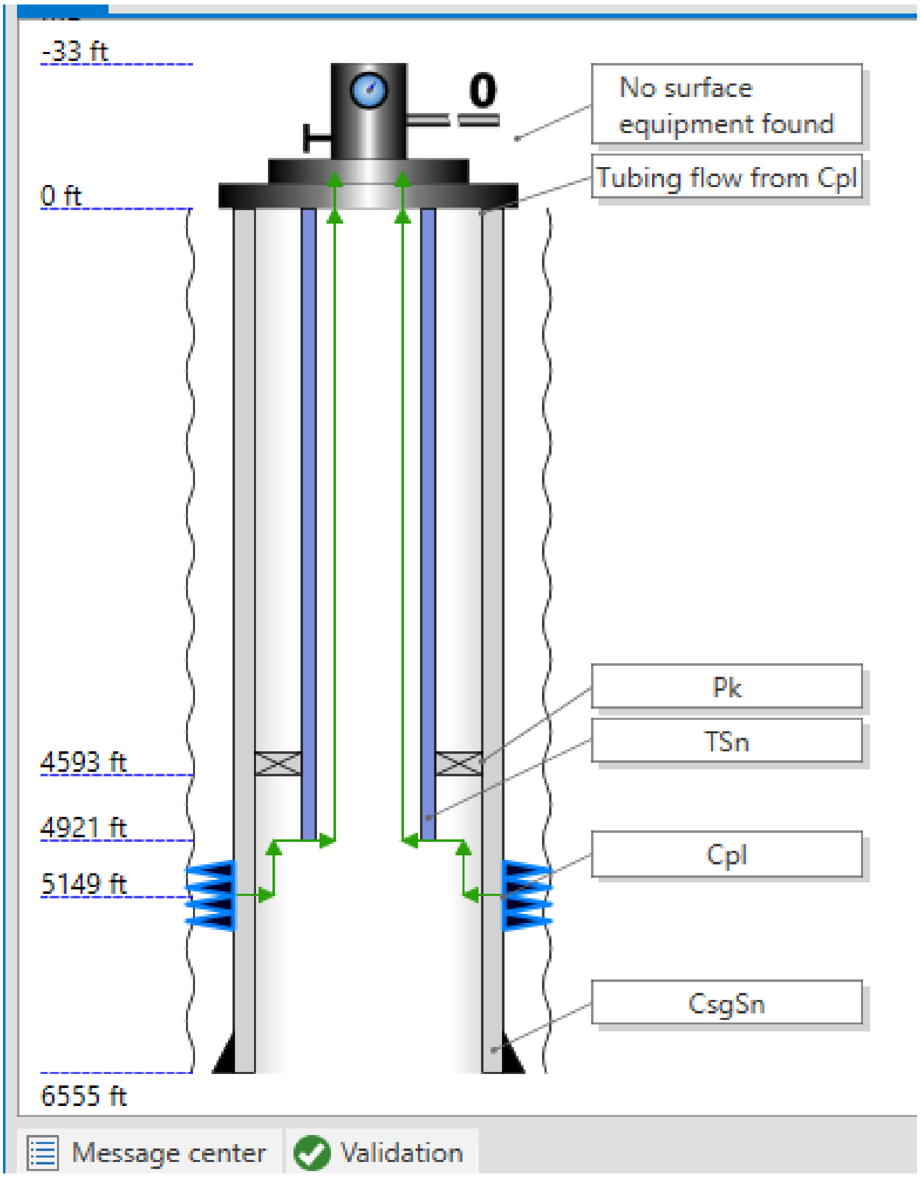


FIGURE (4.11): WELL MOGA COMPLETION

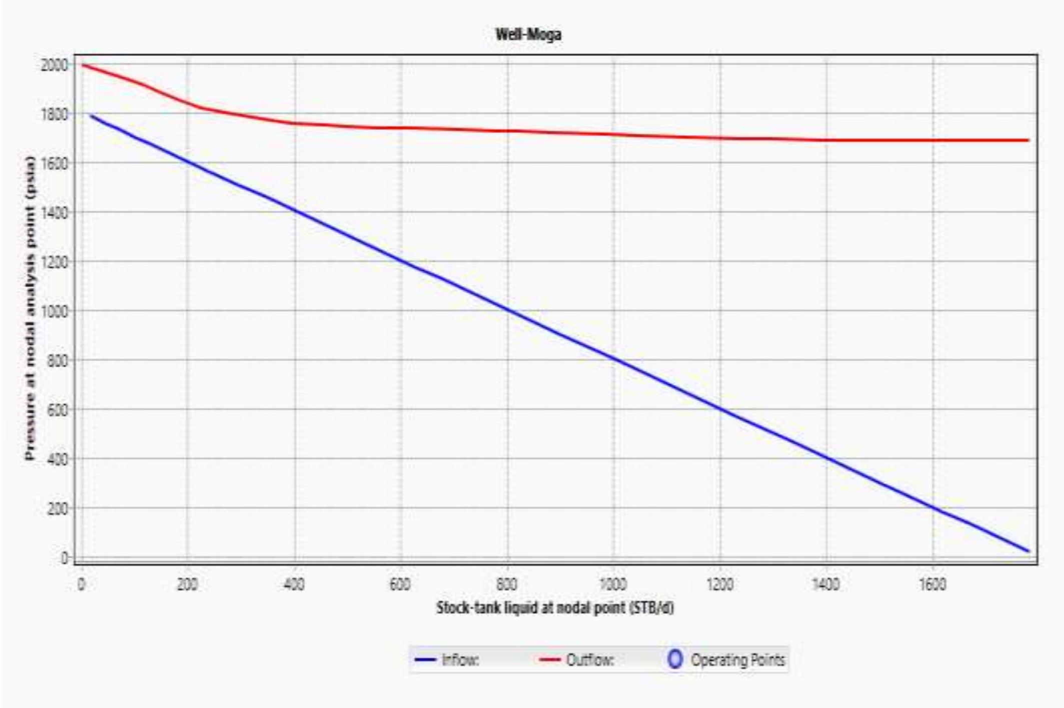


FIGURE (4.12): WELL MOGA NODAL ANALYSIS

Figure (4: 12) represent the performance curve of the IPR well, which shows their stopping production

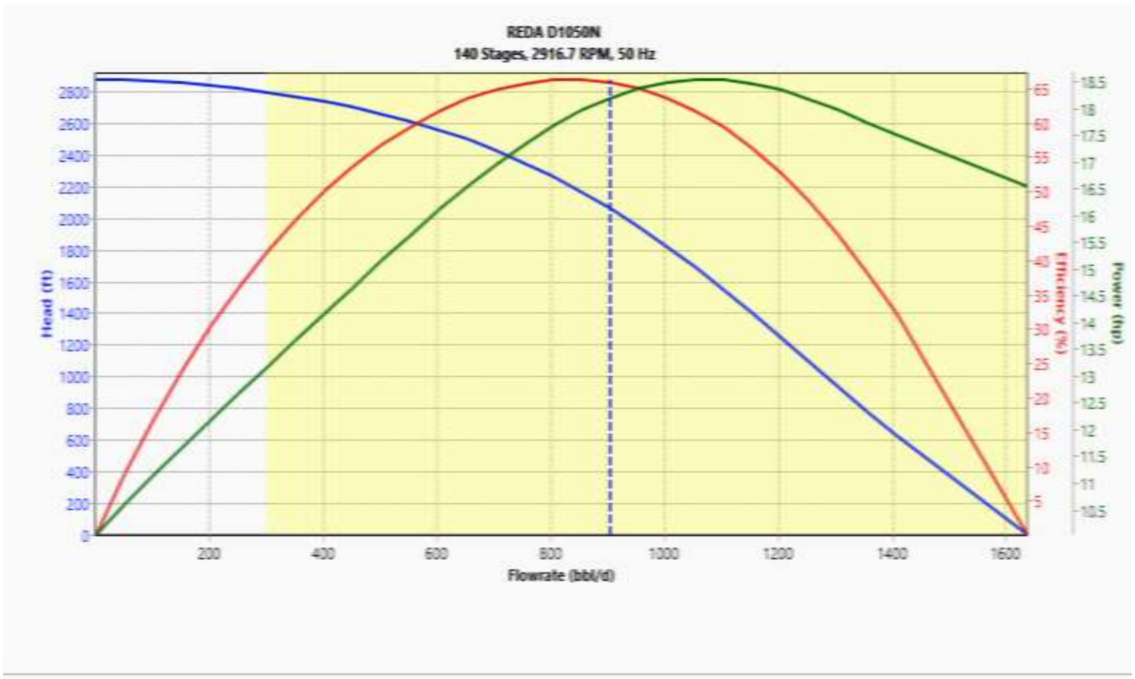


FIGURE (4.13): ACTUAL PUMP PERFORMANCE CURVE

Figure (4: 13) represent the Actual REDA D1050N pump performance curve which indicates the optimum production rate for each pump

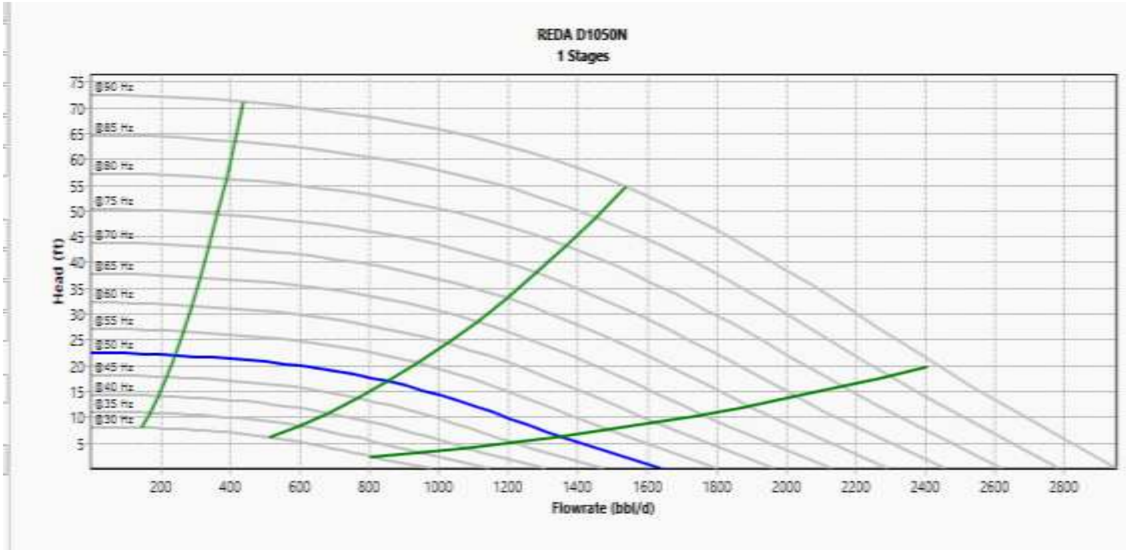


FIGURE (4.14): CATALOG VARIABLE SPEED CURVE

Figure (4: 14) show the relationship between the operating well production rate with the height of the fluid column that must be provided above The pump is to ensure its operation and at different frequencies to operate the pump with an indication of the optimal limits of the pump's operation and are clear Increasing the pump frequency will increase the well production rate, but attention must be paid to the working conditions of the pump Between the two lines, with the minimum and maximum operating conditions, and whenever the condition is close to The line in the middle, which is the optimum operating condition, is better to ensure the pump's working efficiency and the long operating life of the REDA D1050N pump.

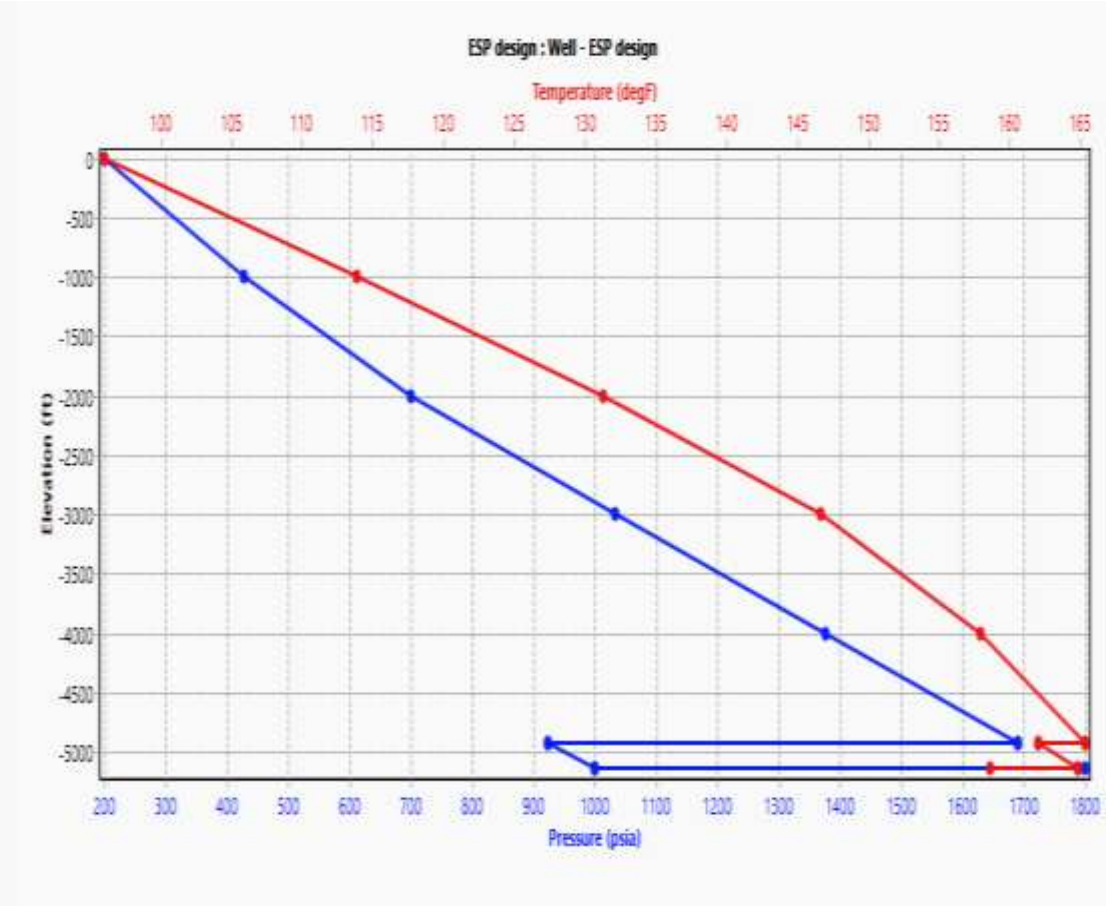


FIGURE (4.15): WELL MOGA P-T PROFILE

Figure (4: 15) illustrate the increase in oil flow pressure at the pump installation depth 1500.0m due to performance The submersible pump, in turn, will increase the pressure difference causing the production, which leads to an increase in the production rate Oil.

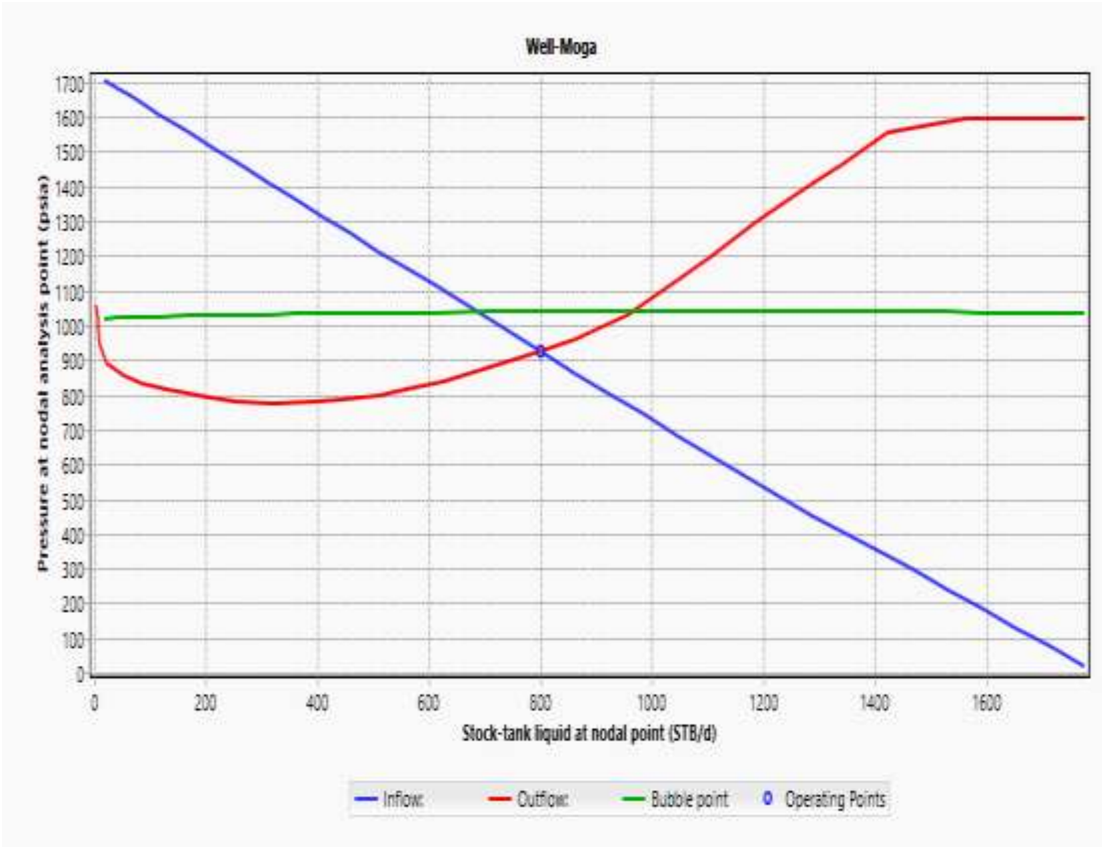


FIGURE (4.16) WELL MOGA NODAL ANALYSIS INSTALLED PUMP

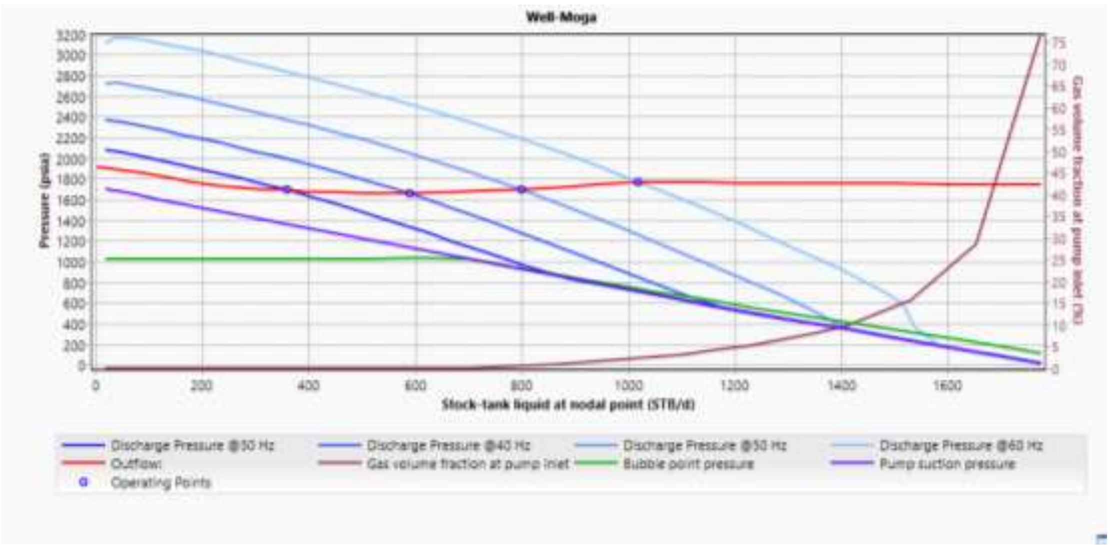


FIGURE (4.17) ESP WELL MOGA PERFORMANCE

Figure (4: 17) show the effect of the performance of the REDA D1050N pump on the performance curve of the IPR well at different frequencies where the pressure is Discharge oil leaving the pump is higher than its intake pressure It intersected with the VLP vertical lifting performance curve at a new point and at high production rates

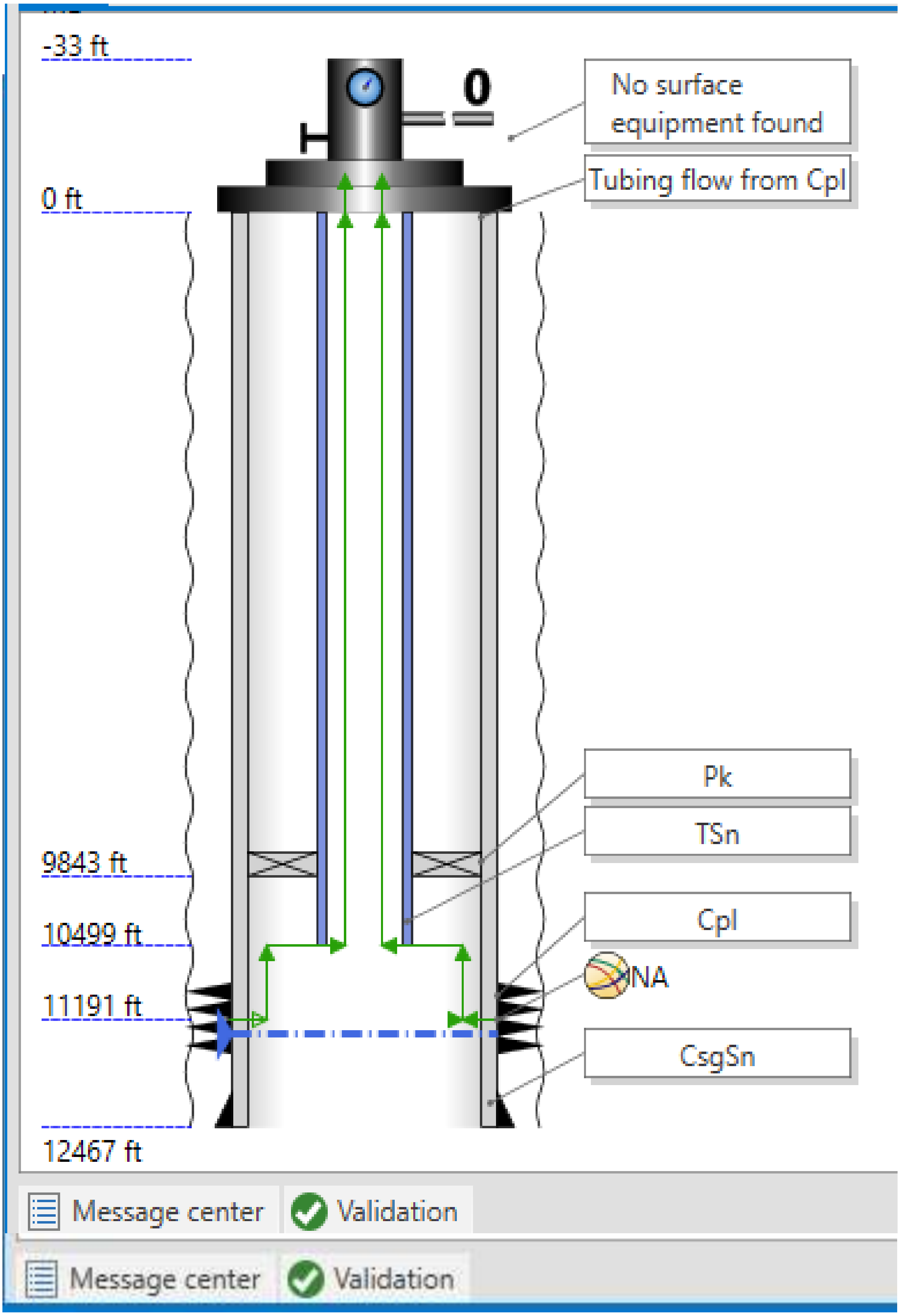


FIGURE (4.18) WELL MOGA INSTALLED PUMP

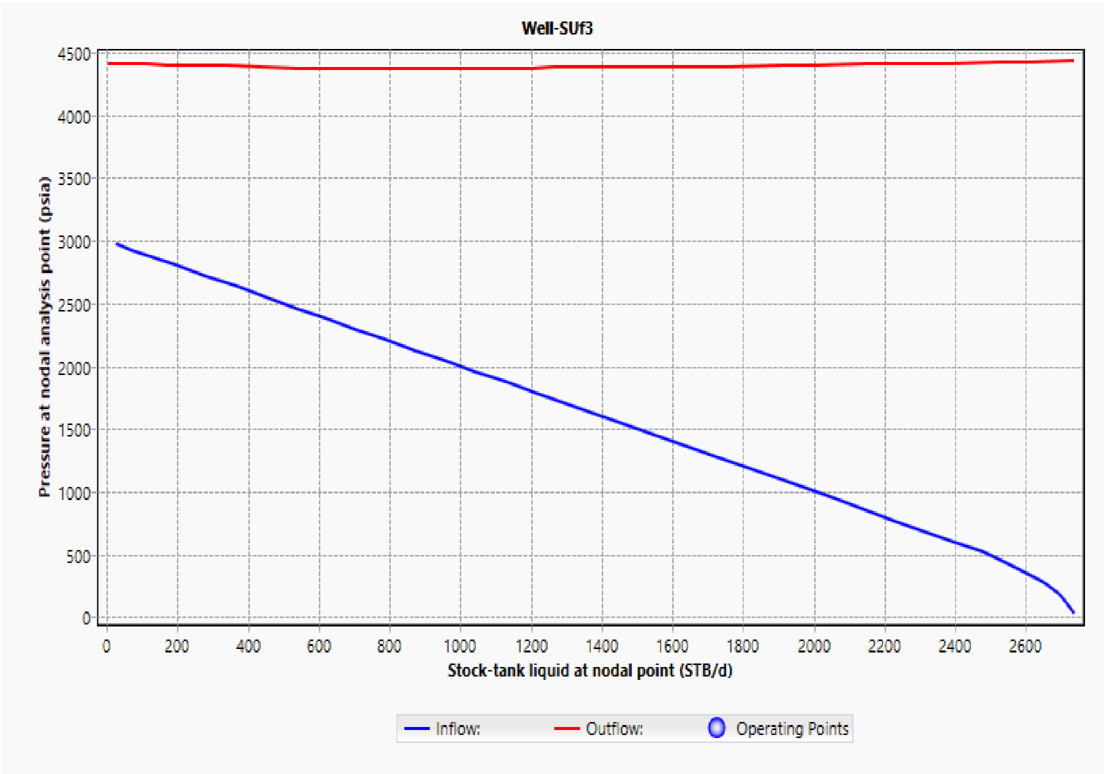


FIGURE (4.19) WELL SUF3 COMPLETION

FIGURE (4.20) WELL SUF3 NODAL ANALYSIS

Figure (4: 20) represent the performance curve of the IPR well, which shows their stopping production

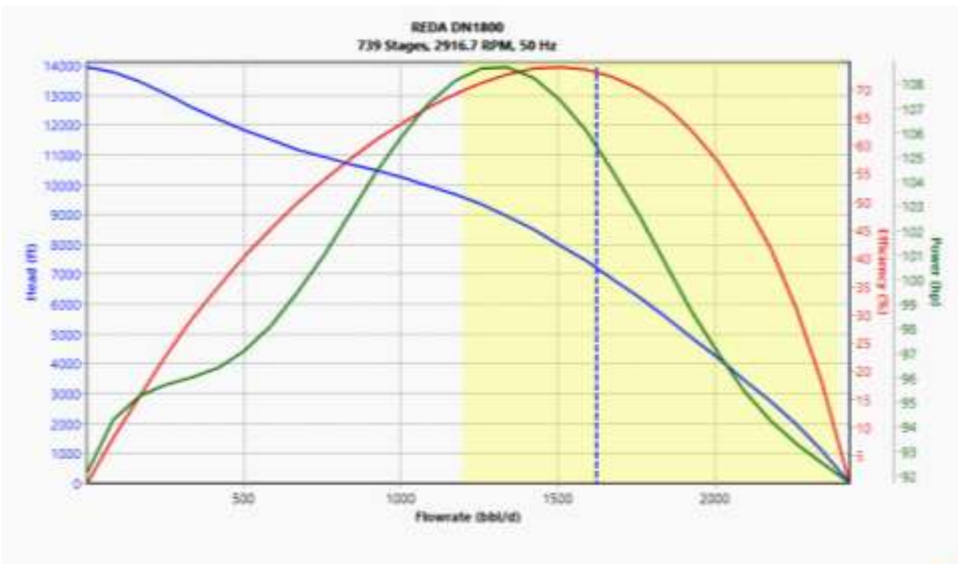


FIGURE (4.21)ACTUAL PUMP PERFORMANCE CURVE

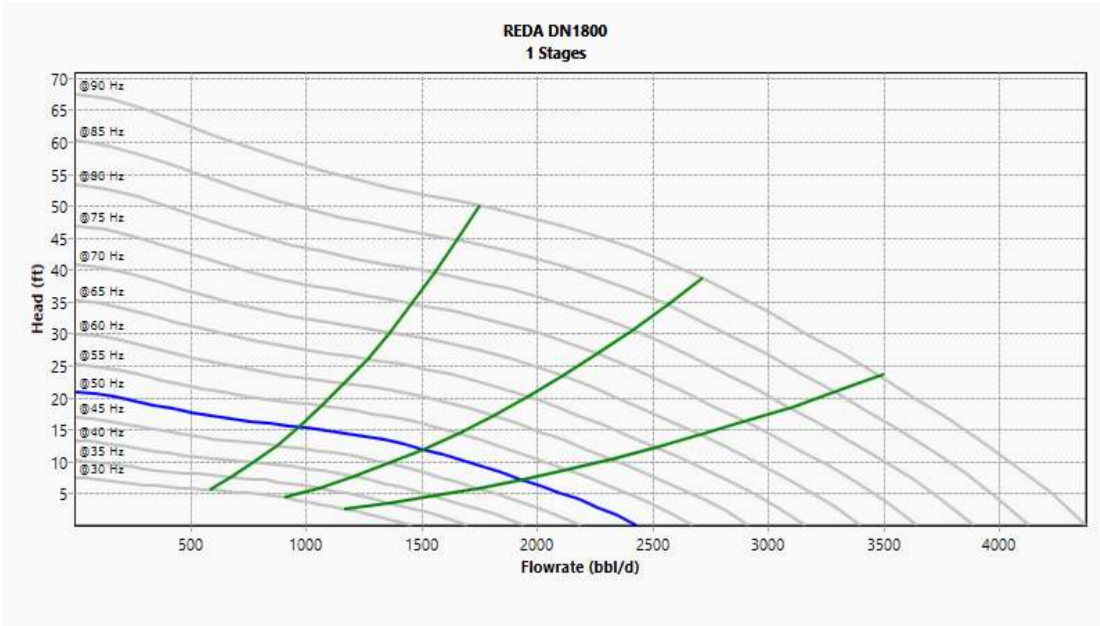


Figure (4: 21) represent the Actual REDA DN 1800 pump performance curve which indicates the optimum production rate for each pump

FIGURE (4.22) CATALOG VARIABLE SPEED CURVE

Figure (4:   22) show the relationship between the operating well production rate with the height of the fluid column that must be provided above The pump is to ensure its operation and at different frequencies to operate the pump with an indication of the optimal limits of the pump's operation and are clear Increasing the pump frequency will increase the well production rate, but attention must be paid to the working conditions of the pump Between the two lines, with the minimum and maximum operating conditions, and whenever the condition is close to The line in the middle, which is the optimum operating condition, is better to ensure the pump's working efficiency and the long operating life of the REDA DN 1800 pump.

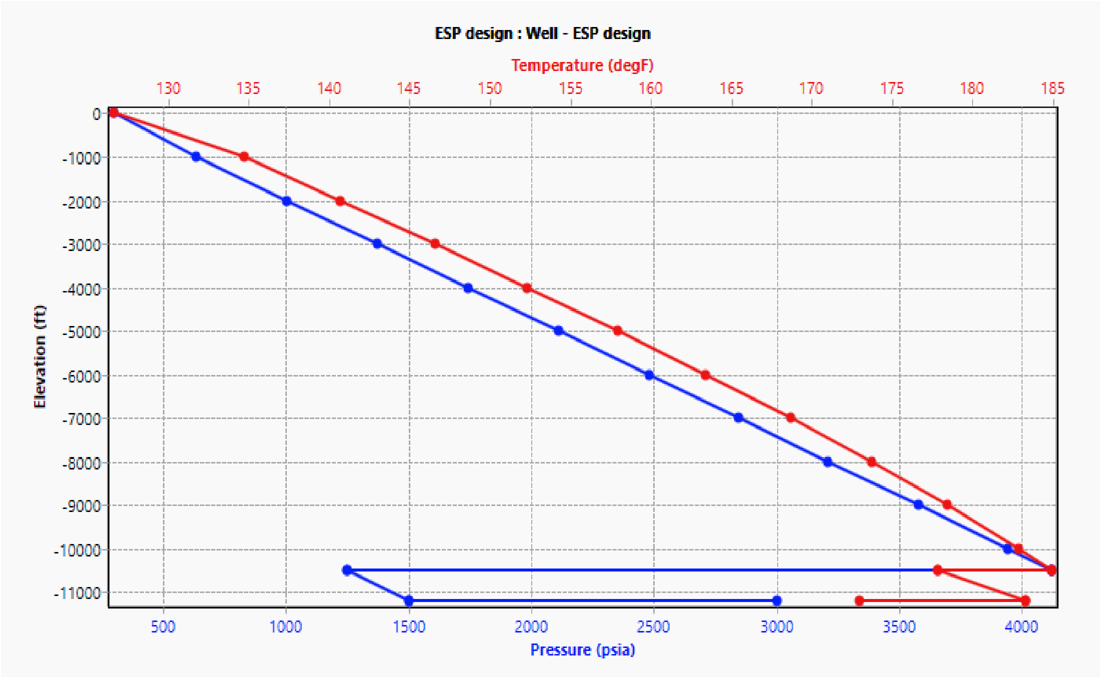


FIGURE (4.23) WELL SUF3 P-T PROFILE

Figure (4: 23) illustrate the increase in oil flow pressure at the pump installation depth 3200m due to performance The submersible pump, in turn, will increase the pressure difference causing the production, which leads to an increase in the production rate Oil.

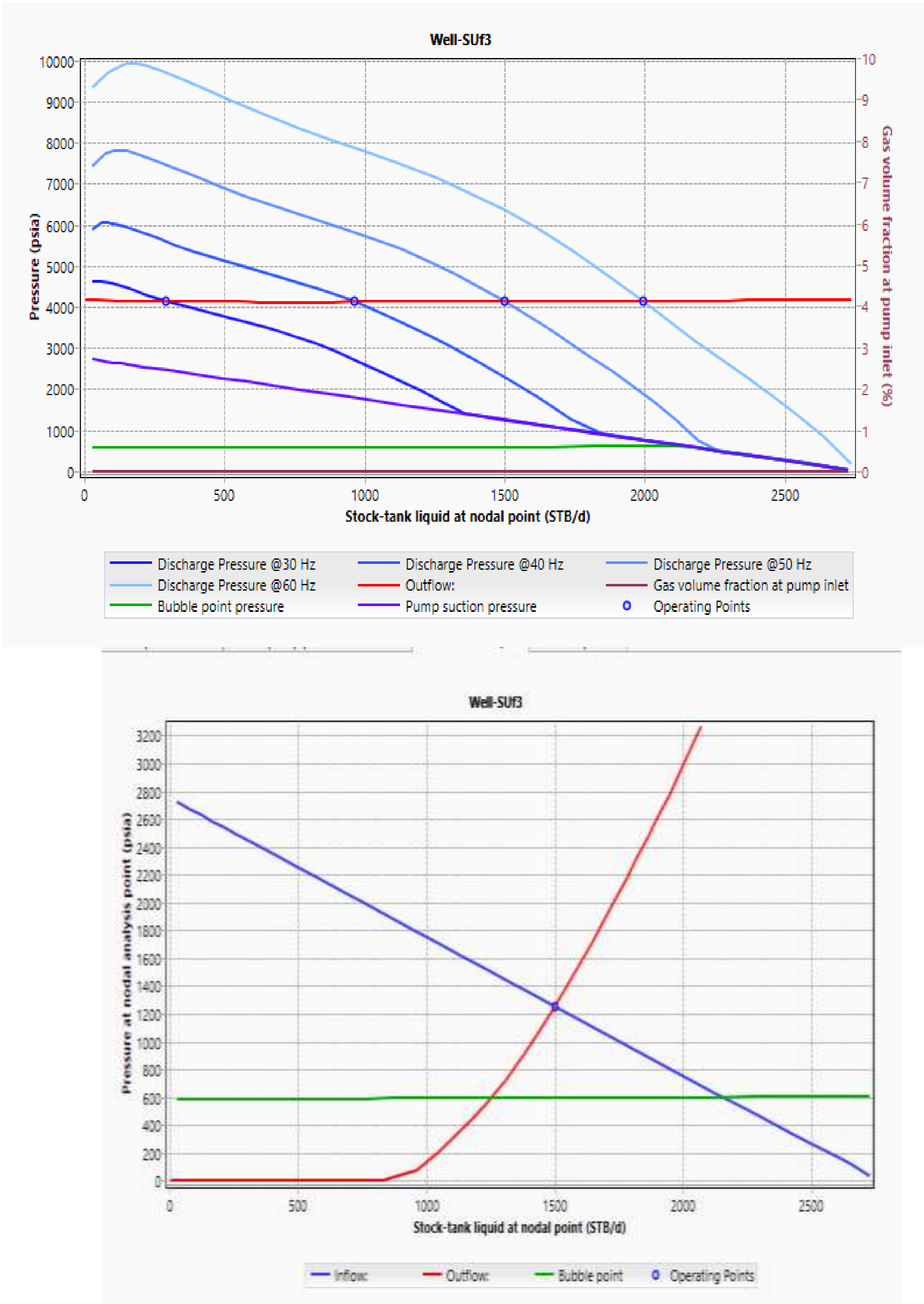


FIGURE (4.24) WELL SUF3 NODAL ANALYSIS INSTALLED PUMP

FIGURE (4.25) ESP WELL SUF3 PERFORMANCE

Figure (4: 25) show the effect of the performance of the REDA DN 1800 pump on the performance curve of the IPR well at different frequencies where the pressure is Discharge oil leaving the pump is higher than its intake pressure It intersected with the VLP vertical lifting performance curve at a new point and at high production rates

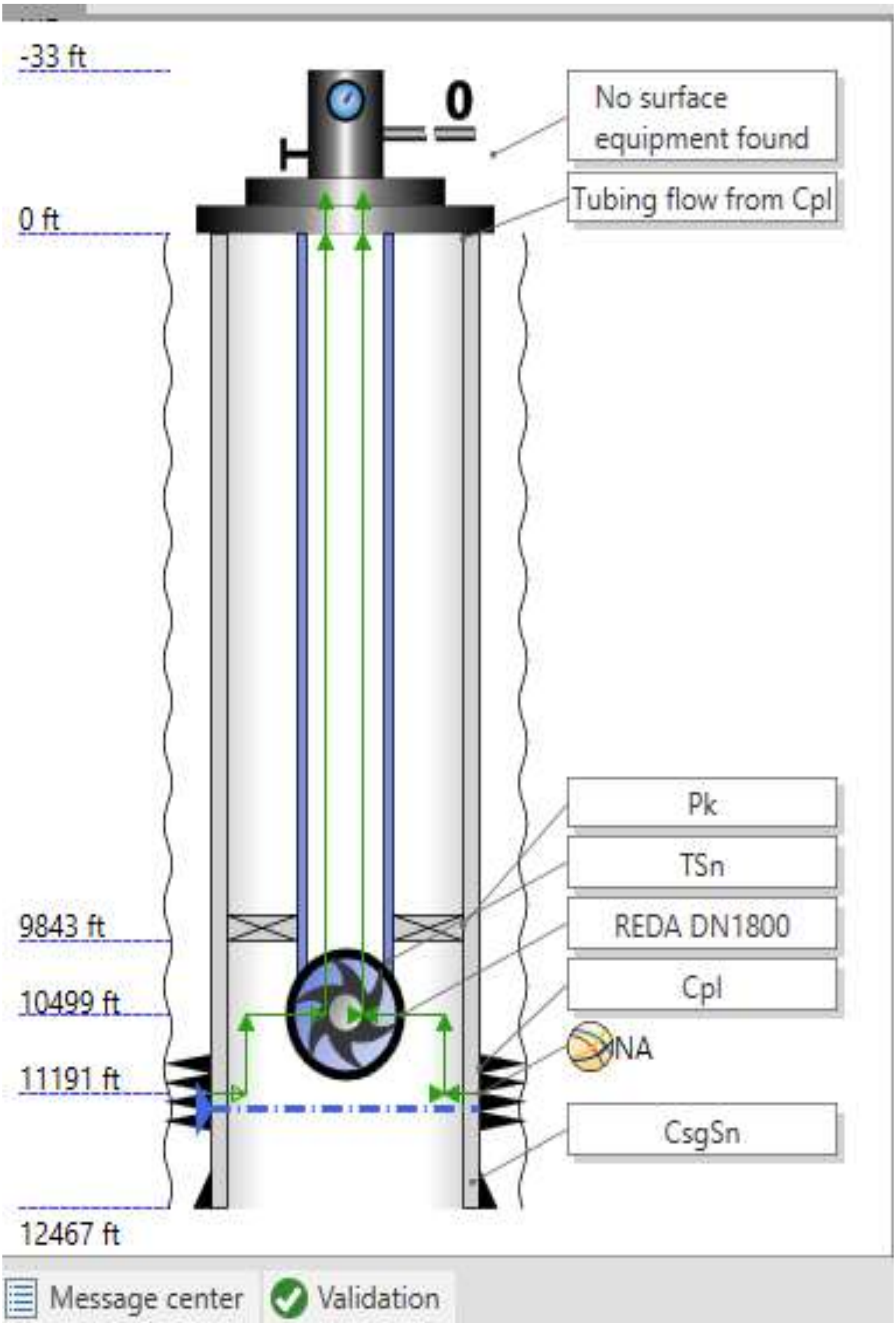


FIGURE (4.26) WELL SUF3 INSTALLED PUMP

RESULTS

Well Name	Optimum Production Rate (STB/D)	The Optimum Pump Stages	Horsepower Requirement For A Possible Production Rate	The Efficiency Of Pump	Selected PUMP
MOGA	799.9879	140	17.68059	66.16982	REDA D1050N 140 stages, 2916.7 RPM, 50 Hz
SUF3	1500.202	737	107.2685	73.82961	REDA DN 1800 737 stages, 2916.7 RPM, 50 Hz

Table (4.1)

Chapter 5

Conclusion and Recommendation

5.1Conclusion:

The design results for the wells MOGA and SUF3 showed, reproducibility The wells that have been suspended from work to production at production rates (0-799.98 STB/D) and (0- 1500.202 STB/D) Respectively.

The capacity of the selected electric submersible pumps for MOGA and SUF3 wells ranged between (300 – 1650 STB/D) (1200 -2400 STB/D). With different proportions to water cut (0 -10%) respectively.

Selecting the appropriate pumps during design so that they do not operate under (above the maximum) or (lesser) conditions It will extend the life of the pump and ensure its efficient operation (Figures 14 -22).

There is no relationship between the number of stages of the pump and the rate of production of the pump, but rather it depends on the percentage of water cut Specifications of the oil produced and the reservoir pressure.

5.2Recommendation:

Setting the pump at low depths enables the choice of large pumps that operate at large production rates and this presence of a reservoir pressure is required to be able to deliver the oil to the depth of the pump to be installed in. In the event that the reservoir pressure is lower, a greater depth must be chosen for the installation of the pump, while obtaining The production rates are lower because the pump will be smaller as the casing diameter is lower.

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