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Heuristic Analysis of ESP Multiphase Flow Data

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DECLARATION

I declare that this project is my own work. It is being submitted to my Master of Science degree in Petroleum Engineering at Politecnico di Torino, Italy. It has not been submitted to any other degree or examination in any other university.

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(signature of candidate)

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DEDICATIONS AND ACKNOWLEDGMENTS

I dedicate this work to my family and friends, for the love, support and faith they always show in me.

I also present my thanks to Prof. Raffaele Romagnoli for his expertise, professionalism, excellent help, guidance and support during my education at Politecnico di Torino and during this project.

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ABSTRACT

Flow rate measurement is the most essential part of well or field surveillance and it is usually conducted on a monthly basis using a test separator. Unfortunately, continuous flow rate measurement of the oil and gas produced by wells has been always subjected to many challenges. Such challenges may exist in offshore or subsea applications and in deserted areas. Similarly, multiphase metering is costly and usually discontinuous (or only performed once per year) due to numerous field constrains and petroleum fluids complexity. Therefore, well production outside the range of a test separator is usually estimated using back allocation techniques which rarely capture the change of flowrate over time. The goal nowadays is to be able to monitor all wells in real-time and to be able to predict well performance and production history. This goal has been a fundamental need in oil engineering for more than 20 years. Such monitoring is usually subjected to many obstacles due to infrastructure problems and high costs of measuring activities. Luckily, we still have the possibility to reach our goal by correlating the available field information with the well flowrate and the mode of its operation. In this context, flow rate prediction is considered as an alternative way for estimating the flow rate of a multiphase mixture without the use of flow meters as direct measurement of flow rates. Instead, a model is developed based on measured performance parameters to estimate the flow rate and therefore monitor the production of each well. This study presents an alternative technique, based on recorded data of an Electrical Submersible Pump (ESP) facility, to obtain accurate and continuous calibration of flow rate and water cut without the obligation to physically measure the flow rate. Being able to predict the flow rate will evade the need to mobilize testing equipment to well sites thereby minimizing cost as well as eliminating HSE risks associated with some difficult environments. This analysis demonstrates how a virtual flow metering can provide the necessary data to characterize well

performance as well as optimizing ESP design and operation. The test separator can be later used to validate the flow rate calculations and to decide whether the model can be used for further field applications.

Table of Contents

List of Figures

List of Tables

List of Equations

List of Abbreviations

ESP	Electrical Submersible Pump
HSE	Health, Safety and Environment
EOR	Enhanced Oil Recovery
FBHP	Flowing Bottom Hole Pressure
IPR	Inflow Performance Relationship
OPR	Outflow Performance Relationship
VLP	Vertical Lift Performance
PI	Productivity Index
OOIP	Oil Originally in Place
Qmax	Maximum Oil Rate
FWHP	Flowing Wellhead Pressure
GOR	Gas to Oil ratio
GLR	Gas to Liquid ratio
HP	Horsepower
SG	Specific Gravity
TVD	True Vertical Depth

BBP	Bubble Point Pressure
BHT	Bottom Hole Temperature
WC	Water Cut
WHP	Wellhead Pressure
PVT	Pressure, Volume, and Temperature
BEP	Best Efficiency Point
THP	Tubing Head Pressure
VFD	Variable Frequency Drives
TDH	Total Developed Head
STB/d	Stock Tank Barrel per Day
H	Head
RPM	Rotation per Minute
GVF	Gas Volume Fraction
API	American Petroleum Institute
VSD	Variable Speed Drive
PIP	Pump intake pressure
PF	Power Factor

INTRODUCTION

Periodic measurements of oil, water and gas rates on a monthly basis is fundamental to monitor the performance of the lift mechanism, as well as measure reservoir depletion and well productivity. For this aim, this kind of monitoring is maintained by operators even in marginal oilfields where this type of test is very costly and challenging. Multiphase flow measurement is mostly used by production engineers to estimate production profiles for late-time production. A sudden change in rate may be associated with different changes in well parameters and it needs to be instantaneously observed. Phase separators were and still the facility used to measure flow rates of upcoming well fluids for it being the cheapest and most practical measuring tool fixed at the surface providing engineers with different flow rates. In the field, rarely multiphase flow rate measurement tools are installed so the flow rate is measured at the processing facility after the fluid is leaving the separator. Usually, several wells produce in the same separator making it difficult to assign production rates to individual wells. Having a model that allows rate prediction would be very helpful as it eliminates the necessity for direct measurement methods and consequently reduces capital costs for the installation and maintenance of an expensive multiphase flow meter.

The Electrical Submersible Pump (ESP) is one of the most known and used artificial lifting method and it is used to increase the production of a well by extending its lifetime. During the operation of the ESP performed in our study and despite the efficiency of the method, numerous parameters were recorded leading to a number of uncertainties when choosing the optimal combination of recordings for perfect operation. Therefore, it is key to be able to develop a tool or a model for selecting the optimal mode of operation for ESP on the dynamic changes in field parameters such as flow rates of the phases, pressure, temperature, PVT... etc.

The purpose of our work is to be able apply a mathematical model built to predict the flowrate based on the measured parameters of our ESP facility. Such tool requires constant calibration and verification of data to compare with the actual performance of the well. It also can be a backup source of information in parallel with real sensors. This increases reliability of the system, avoids downtime and reduces associated losses.

The first chapter of the thesis study presents a small explanation of multiphase flow importance and the second chapter describes the basics of well performance. Further explanation of ESP methodology, design and function will be elaborated in the third chapter. Later in chapter four, the case study, the description of the model, the analysis and the observations are presented based on the data analysis of the ESP facility parameters.

Chapter 1: Purpose of Multiphase Flowrate Measurement

During the production of an oil well, a mixture of liquids and gases arises to the surface. Multiphase flow is defined by the presence of different phases of flowing fluids. A clear example of multiphase flow is gas injection into a well.

A phase change is likely to occur along the travel path which is subjected to many conditions faced along the way. For example, at well bottom, the pressure is high enough to keep the flow in one phase. Yet, dissolved gas starts to escape progressively from the flowing liquid when travelling up the well due to the gradual decrease in pressure. This will eventually result in a multiphase flow.

Laminar and turbulent flow are usually the two known flow regimes in single phase flow. Having more than one phase in a vertical flow, other flow patterns are considered. At low velocities, slug flow is observed whereas at high velocities, gas and liquids are mixed and an annular flow is observed. Figure 1 shows flow regimes in vertical flow. Phase velocities may be defined at a certain position in the pipe and flow regimes are considered a very useful tool for friction gradient calculations.

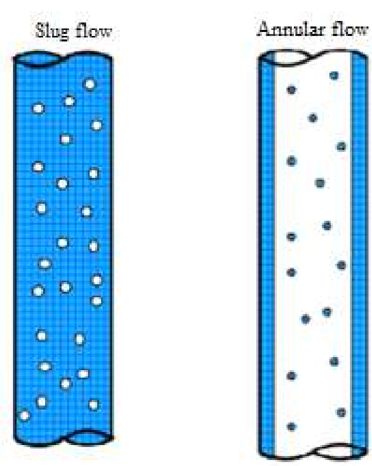

Figure 1: Flow regimes in vertical flow

ESP pump system may be subject to pump degradation which is greatly affected by different viscosities and multiphase flow. Viscosity has a negative effect on pump performance. An increase in viscosity will powerfully reduce pump efficiency which is marked by a reduction in head and flow. A greater brake horsepower will be consequently required.

Flow rate measurement is very essential. Reservoir surveillance is typically based on flow rate continuous testing because real-time delivery of any change in measured data will be translated into a change in flowrate. Therefore, it is hard for field production engineers to constantly measure flow rate since they are busy trying to achieve optimum well design and monitor pump operating point. Flow rate can help field engineers to decide over ESP design and parameters and whether additional stages are required in order to keep ESP within its operating range. Also, history matching (simulation) of flow rate and pressure measurements can help in estimating reserves. Therefore, different drawdown scenarios and production profile become an easy task for production engineer to estimate for late-time well production. High frequency and high-resolution flowrate trends generated from an ESP available gauge data are the key to estimate reservoir properties, obtain well performance and perform reservoir analysis.

For example, in an offshore environment, where low flow rates wells are economically marginal, the absence of a flow rate trend with time make inflow characterization and reservoir surveillance very difficult. Moreover, conventional well production and reservoir analysis can be confidently performed with the possibility of calculating flow rates using an ESP facility and thus analyzing the data available and combine the results into an effective model able to characterize well performance. This is a great way to optimize both the well production and the artificial lifting method used which is in our case an ESP.

To conclude, a good flowrate estimation supports surveillance activity by regularly examining the evolution of ESP operating point, ESP power consumption, reserve estimation, depletion, drainage area pressure and PI over time.

Chapter 2: Well Performance

Well performance is a measurement of a well's production based on the well producing capacity, the pressure drop and the flow rate and it is dependent on many variables including pressure, fluid characteristics and formation properties. Well performance is estimated by the productivity index (PI) which is a measure of well potential or well's ability to produce. Nevertheless, this is assumed to be true for well producing under single-phase flow conditions as gas is dissolved in the liquid phase (pressure above bubble point) and the productivity index follows a constant straight-line trend. Through production, the pressure decreases below the bubble point pressure and the gas dissolved in oil gradually starts to escape creating a multiphase flow behavior. Consequently, a curved relationship between flow rate and pressure occurs making constant PI concept no longer applicable. Therefore, other techniques beside PI must be applied in order to predict the well performance. Inflow Performance Relationship (IPR), Vertical Lift Performance and Outflow Performance Relationship (OPR) are the most common techniques or methods used for oil well performance prediction. Before detailing these techniques and models, a brief explanation of a reservoir different drive mechanisms will be given.

1. *Drive mechanisms*

A drive mechanism is defined as the required force that pushes the produced fluid out of the reservoir pores towards the wellbore. The common drive mechanisms that control oil production are the following:

- Water drive
- Solution gas drive
- Gas cap drive

- Rock or compaction drive

Water expansion or Water drive mechanism:

Throughout the production, the pressure around the borehole starts to decline and drop triggering the aquifer water to expand displacing the oil and gas from the pores of the reservoir towards the wellbore. A strong natural water drive provides a very good pressure support from the aquifer with minimal pressure drop at the borehole. This drive mechanism is considered very effective (up to 50% of oil recovery) when the aquifer size is much larger than the reservoir size and is more effective in oil reservoirs than in gas reservoirs. If the aquifer size or volume is smaller, a partial water drive mechanism will result causing a reduction in recovery.

Gas expansion, dissolved gas or solution gas drive mechanism:

As the pressure drops below bubble point pressure due to advanced production, gas primarily dissolved in the oil liquid phase starts to gradually escape. In oil reservoirs with little or no water drive, oil expansion due to gas expanding in solution can be very effective to drive oil to wellbore.

Gas cap drive mechanism:

Reservoirs with gas cap drive mechanism usually have a very limited aquifer; little or no water drive. Gas present freely in the reservoir or in a gas cap expands providing enough energy to move the hydrocarbon fluids to the wellbore and replace them in reservoir pores. Under gas cap drive, up to 35% of the oil originally in place (OOIP) can be recovered.

Rock or Compaction drive mechanism:

Due to loading of sediments during burial, normally cause rocks to compact beyond elasticity limit, reducing their pore volume and forcing out the formation fluid. Rock drive is common in shallow reservoirs or in reservoirs with unconsolidated sediments.

Drive mechanisms can occur independently or in combination. They are classified as primary recovery techniques. Secondary and tertiary oil recovery methods are often used to reach better performance. Enhanced Oil Recovery (EOR) models are frequently implemented using gas lift and downhole pumps for example as advanced recovery techniques.

2. *Inflow Performance*

IPR of a well is a relation between the production rate and the flowing bottom hole pressure (FBHP). With this relationship, maximum oil production rate can be estimated and can be used to estimate other production rates for other FBHP at the current average reservoir pressure. The data required to plot the IPR are obtained by measuring the production rates under various drawdown pressures (difference between static and FBHP). The PI concept was used as the simplest method to describe the inflow performance of oil wells and it is valid for single-phase flow conditions. In the following steps, a brief description of PI concept will be given followed by the Vogel's IPR for multiphase flow.

PI concept was established using the following assumptions:

- Radial flow around the well
- Single- phase liquid flow
- Homogeneous distribution of permeability
- Formation fully saturated with the liquid

Darcy equation describes fluid flow in porous media and is the following:

Equation 1: Darcy Equation

$$\frac{q}{A} = \frac{k}{\mu}\frac{dp}{dl}$$

Using the above assumptions, Darcy's equation can be written as

Equation 2: Darcy Equation based on assumptions

$$q = \frac{0.00708kh}{\mu B ln\left(\frac{re}{rw}\right)}(P_R - P_{wf})$$

Where	q	=	liquid rate, STB/d
	k	=	effective permeability, mD
	h	=	pay thickness, ft
	μ	=	liquid viscosity, cP
	B	=	liquid volume factor, bbl/STB
	r_e	=	drainage radius of well, ft
	r_w	=	radius of wellbore, ft
	P_R	=	average reservoir pressure, psia
	P_{wf}	=	flowing bottomhole pressure, psia

The fraction on the right-hand side of the equation is mostly composed of constant parameters which can be combined into a single coefficient called PI. Therefore, the PI equation will be the following:

Equation 3: Darcy simplified equation

$$q = PI(P_R - P_{wf})$$

Equation 4: PI formula

$$PI = \frac{q}{(P_R - P_{wf})}$$

From Equation 3, we can state that the liquid inflow into a well is directly proportional to pressure drawdown. The plot of FBHP versus liquid rate will generates a straight line. This will allow us to calculate the liquid flow rate at any FBHP for known PI and average reservoir pressure. In case the PI isn't known, it can be measured from reservoir parameters or by measuring q at several FBHPs.

As already mentioned, the PI concept is only valid for single-phase flow and will show a curved graph for multiphase flow conditions. When pressure goes below bubble point, free gas starts to escape from the solution which will cause an increase of gas relative permeability. Accordingly, PI will decrease since it is dependent on the effective permeability of oil and therefore the FBHP versus rate graph will no longer show a straight line.

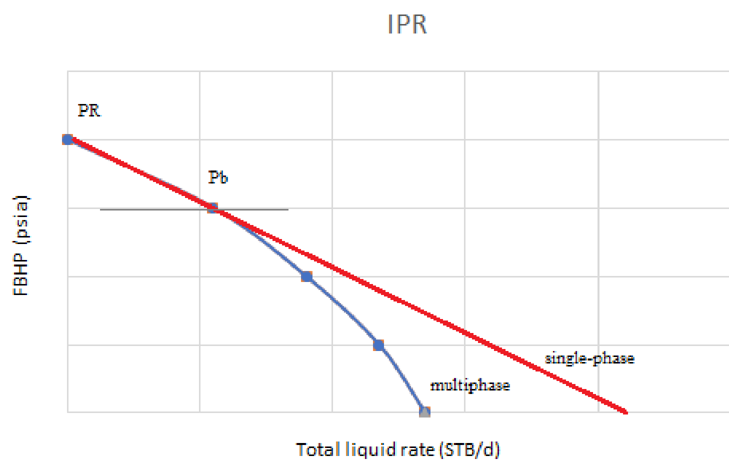

Figure 2: IPR with PI concept

To be able to predict well performance in case of multiphase flow production, Vogel was the first to present an easy-to-use IPR based on computer simulations. Vogel considered cases below bubble point pressure and varied many parameters including fluid properties, rock characteristics and drawdowns. His empirical IPR illustrates the same shape that the IPR curves calculated exhibited and is given by the following dimensionless equation:

Equation 5: Vogel IPR equation

$$\frac{q}{qmax} = 1 - 0.2\frac{P_{wf}}{2} - 0.8(\frac{P_{wf}}{P_R})^2$$

To use this equation, the engineer needs to obtain an estimate of the average reservoir pressure at the time of the test by determining the oil production rate and FBHP from a production test. Next, using this information, the maximum oil production rate can be determined and therefore can be used to estimate the production rates for other FBHPs at the current average reservoir pressure. This equation is considered reliable and can be used for almost any well producing at a pressure below bubble point.

It is necessary to mention that for fractured, deviated or horizontal wells and for wells flowing at high/low rates, exhibiting transient flow or non-Darcy flow behavior, etc., numerous models are designed to estimate performance.

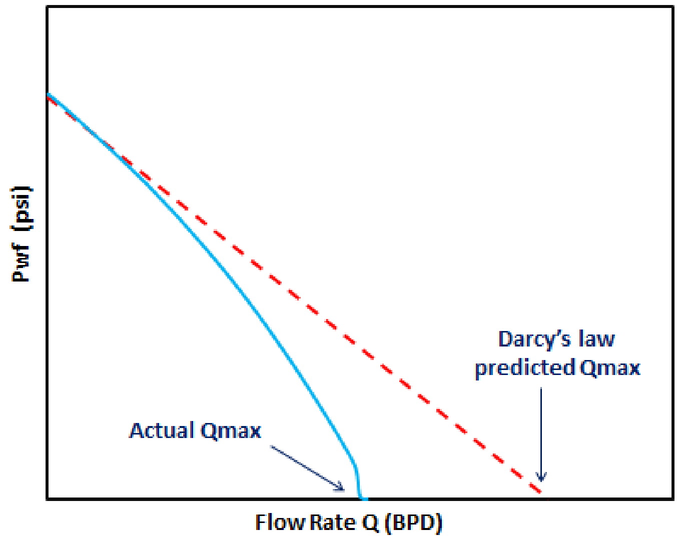

Figure 3: IPR from Vogel vs Darcy (PI)

3. *Outflow Performance or Vertical Lift Performance (VLP)*

VLP curve describes a relationship between flow rate and FBHP. It shows how much pressure is required to lift a certain amount of fluid to the surface at a given well head pressure. In order to build the VLP curve, the calculation of FBHP is mandatory given the flowing wellhead pressure FWHP for different well rates. In order to do so, the energy balance equation needs to be solved:

Equation 6: Energy balance equation

$$\frac{dp}{dh} = \left(\frac{dp}{dh}\right) GRAVITY + \left(\frac{dp}{dh}\right) FRICTION + \left(\frac{dp}{dh}\right) KINETIC$$

<u>Gravity component:</u>

This component, also called hydrostatic, represents the change in potential energy due to gravitational force acting on the fluid mixture:

Equation 7: Gravity component of Energy Balance Equation

$$\left(\frac{dp}{dh}\right)G = \rho g sin\beta$$

Where	f	=	fluid density
	β	=	pipe inclination angle
	g	=	gravity constant

Friction Component:

This component denotes the irretrievable pressure losses along the pipe as the fluid exerts friction against the pipe inner walls:

Equation 8: Friction component of the Energy Balance Equation

$$\left(\frac{dp}{dh}\right)F = \frac{1}{d} f \frac{1}{2} \rho v^2$$

The type of flow is determined by Reynold’s number:

Equation 9: Reynold number

$$Re = \frac{\rho v d}{\mu}$$

Where f = friction factor

d = pipe inside diameter

v = fluid velocity

μ = fluid viscosity

The boundary values between laminar and turbulent flow regimes are:

$Re \leq 2500$	Laminar flow regime
$2500 \leq Re \leq 5000$	Transition flow
$Re > 5000$	Turbulent flow regime

The friction factor for laminar flow is calculated using Moody Friction Factor $f = 64/Re$.

f for turbulent flow regime can be calculated using other correlation.

Kinetic component:

This component is also called acceleration component and it shows the kinetic energy changes of the flowing mixture that is proportional to flow velocity changes:

Equation 10: Kinetic component of the Energy Balance Equation

$\left(\frac{dp}{dh}\right)K = -\rho v \frac{dv}{dh}$ (often negligible compared to the hydrostatic and friction components)

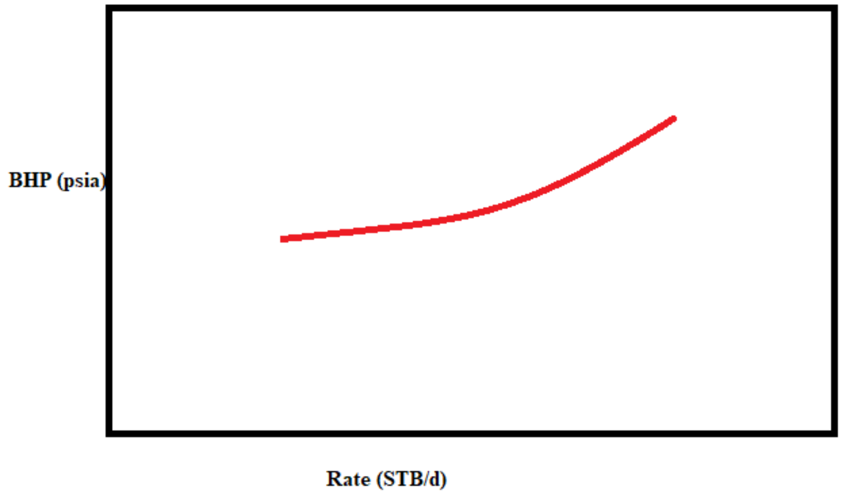

Figure 4: VLP curve

To clarify, the system is described as an energy balance equation declaring that energy is conserved over the length of tubing. This means that the energy leaving the system plus the energy exchanged by the fluids and the surroundings must be equal to the energy entering the system by the flowing fluid.

The outflow performance of a well is dependent on many factors including:

1. Tubing size:

   Tubing size has an effect on pressure loss; the diameter of tubing can be increased to a certain limit. As we can see from the friction component equation, when the diameter increases the pressure gradient will decrease due to friction. Velocity of the mixture, which is defined as rate over pipe cross section, for a very large pipe diameter will be insignificant and won't be enough to lift the fluid up. Hence, the tubing starts to load with liquid leading to an increase in hydrostatic pressure.

2. Liquid rate:

Additionally, from the friction component equation, we can perceive that an increase in liquid rate or fluid velocity will increase friction losses. Therefore, liquid flow rate has an effect on pressure loss.

3. GLR or GOR:

When the gas-to-liquid ratio is increased, fluid density is reduced leading to a reduction of the hydrostatic gradient. Additionally, GOR increase has a sever effect on the friction losses. When GOR increases, frictional forces increase to an extent that they might get ahead of hydrostatic forces which consequently will cause an increase in bottom hole pressure. Hence, GLR has a very important effect on pressure loss.

4. Water cut:

Briefly, water cut will increase liquid density leading to an increase in the hydrostatic forces and the bottomhole pressure.

Hence, the outflow performance curve shows the relationship between the total tubing pressure drop and a surface pressure value with total liquid flowrate. It is dependent on many factors that affect the pressure loss. These factors include fluid properties, fluid type, water cut, tubing size, GLR and liquid flow rate.

4. *Operating Point*

Plotting the IPR and VLP curves together on the same FBHP versus Rate graph will enable us to find the producing rate at the operating point. The operating point is the intersection between IPR and VLP curves as shown below:

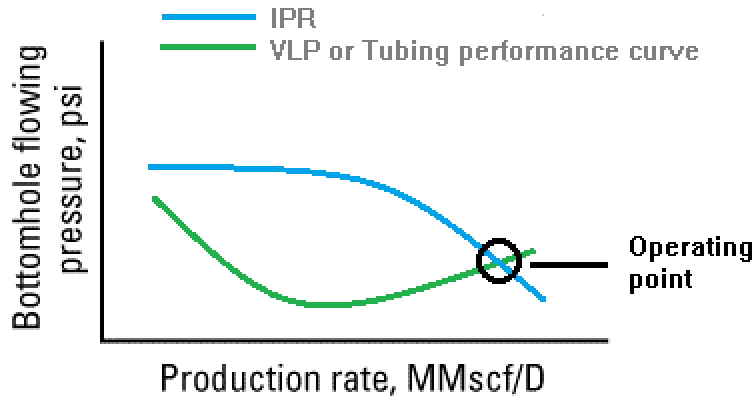

Figure 5: Operating point

To conclude this part, being able to calculate the inflow properties with history matching of a reservoir simulation is necessary to surveil the well production especially in case of production drop to be able to check where the reservoir was lacking pressure support. The fall in production may cause many severe problems. These problems can therefore be remediated by changing tubing head pressure (THP) and ESP parameters without the need to change the drawdown. Additionally, having enough test data with which PI, skin, depletion, etc. can be estimated is a very reliable way to monitor ESP performance.

Production optimization for wells equipped with artificial lifting methods can be reached by performing an IPR and VLP curves for the well.

Chapter 3: Electrical Submersible Pumps (ESP)

1. *Introduction and History of ESP*

After completion, a naturally flowing well can produce providing energy source up to 40 years. This energy stored into the reservoir is provided by reservoir pressure and formation gas and is enough to move fluid from the pores. After a certain period, natural drive mechanisms of the reservoir become not strong enough to push oil to the surface with the desired flowrate and therefore, a decline in oil production of a well or a field occurs. This is where Artificial Lift process is introduced encouraging oil recovery by increasing pressure within the reservoir. Electric Submersible Pump (ESP) is a very well-known artificial lift method mostly used to increase production in the late life of a well or a field. Other artificial lift methods include Sucker Rod Pumps, Gas lift, subsurface Hydraulic pumps, piston lift, etc.

The principle of ESP relies is based on the installation of multistage centrifugal pump. Each stage consists of an impeller that provides energy to the fluid as kinetic energy in form of pressure, and a diffuser that converts part of this kinetic energy into additional pressure gain. The fluid passing through the pump stages increases its pressure enough to add to reservoir pressure, leading the fluid to the surface at the desired flow rate. ESP is one of the most widely used artificial lift method intended for production volumes when comparing with other methods such as gas lifting. It can be applied for both heavy and light oil production.

ESP was invented first in the 1910s when Armais Arutunoff invented the first electric motor that could operate in water. In 1916, he was capable of coupling a centrifugal pump with a motor for dewatering mines and ships. Later in 1923, he travelled to the US and was able to sign a contract to prove the concept that he developed. In 1987, a new company named REDA Pump Co. was initiated based on the famous REDA company that Mr. Arutunoff opened in Berlin, and was later merged with Schlumberger in 1998. Nowadays, ESP reached more than one hundred thousand installations globally. Despite the high-efficiency of the facility in producing high flow rates, it is allied with several problems when dealing with high viscous flow, surging, gas locking or changing flow rates. Gas presence is a main cause for ESP deterioration.

The possibility of using ESP as a flowrate measuring tool when calibrated in field is real and deserves consideration. As a matter of fact, at first, the FBHP is sufficient to overcome the pressure losses in the well and in the flow travel line to the separator which is what makes the oil well able to flow naturally. Later on, the FHBP decreases due to proceeded production creating an increase in pressure losses along the well which impedes the natural flow and the well is risked to die. An increase in density is then observed with an increase in water cut. The possibility to have ESP as a continuous flow meter will be very helpful to monitor oil production.

2. *Method selection*

In order to reach the highest performance of any oil or gas well, the proper and the most economical artificial lift method must be selected. Choosing the optimal artificial lift method is usually dependent on the depth, location, reservoir characteristics, well conditions (high viscosity or sand production) and the rate in which a particular method can function. For instance, delayed production, long term servicing costs, poor efficiency (require the need for excessive energy) can all be considered as factors affecting the optimal artificial lift method selection. Moreover, having a short power supply will eliminate the option of the use of an ESP.

Despite the efficiency of ESP as an excellent method for ideal artificial lift, the use of ESP usually requires a reliable electric power supply and is considered poorly efficient for high temperature or electric nonfunctional areas. Changes in fluids properties and downhole conditions can affect the whole system. The operating cost of ESP depends on whether the well is subject to high pulling costs in offshore operations (short run life) or high energy costs for high horsepower intake need (low costs if electric power is available). ESP system is simple to design when downhole equipment is properly setup, gives high efficiency in high-rate wells, and requires good operating practices and good rate data.

Below is presented a short table of the advantages and disadvantages of ESP which can give a clarification of where ESP could function. Each well is considered independent and may need its own electric support system. The run life of an ESP depends on its individual components, the temperature, the reduction, the motor horsepower, failure rates, and most importantly the economic restrictions of the system including maintenance costs, repair costs, fuel costs and expected revenue from the producing well.

Table 1: Advantages and Disadvantages of ESP

ADVANTAGES	**DISADVANTAGES**
Offshore applications	Need of high voltages
Simple operation and simple surface equipment	Only applicable with a stable high-voltage electric power supply
Availability in different sizes	Cable problems with high temperature and abrasive conditions
Can lift high volumes	Cannot withstand high downhole temperatures

Can perform under corrosion	Depth limitations (cable costs and extended power installation downhole)
Easy installation of downhole equipment	Gas production is not so efficient
Low cost for high lifting volume	In case problems come upon, the monitoring of the whole downhole equipment takes time and the cost of changing equipment is often high
Pumps nowadays are made to run under tough conditions; they can be applied in deviated wells with dog leg severity of less than 9°/100 ft	Casing sizes restrictions
Designed for oil and water wells	Running and pulling the tubing string may cause damage to the power cable
Can lift at production rates ranging from 20 to 60,000 B/D and at depths of up to 15,000 ft	Not applicable for high GOR or solid production

3. *ESP design and Working Principle*

ESP design is principally described in 3 main parts: the surface controller, the tubing string and power cable and the downhole equipment. The basic system design includes a centrifugal pump and an electric motor run on a production string which is connected to the surface equipment by electric power cables.

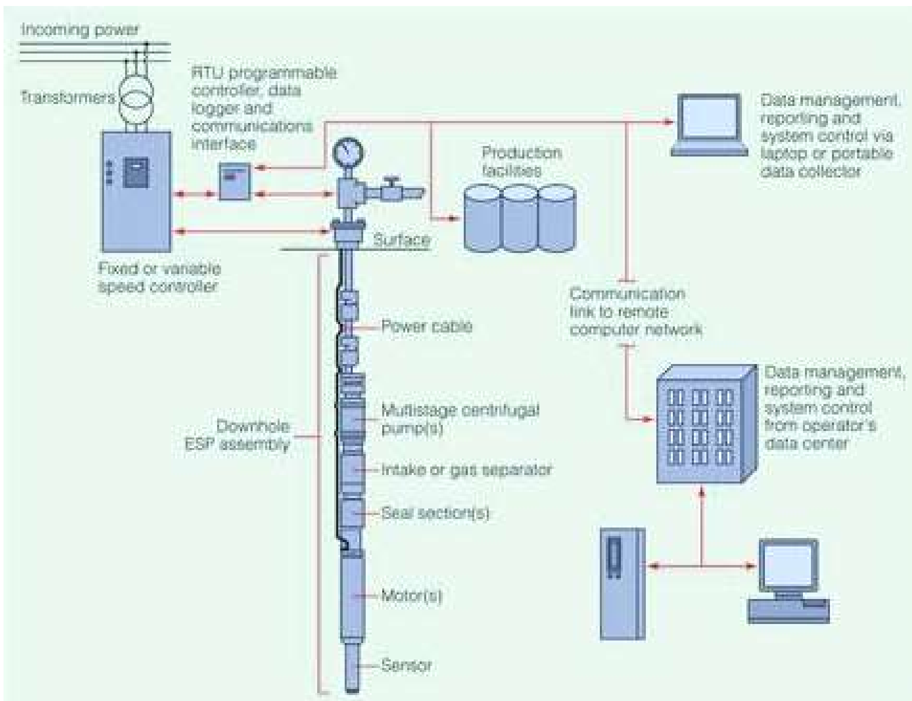

Figure 6: ESP system

The surface equipment is composed of transformers, Variable Frequency Drives (VFD) and switchboard, junction box, wellhead, and monitoring and automation section. The surface controller provides electric power to the ESP and serves as a monitoring base section for ESP downhole equipment. Relying on the data recorded, the surface controller offers protection, control, and monitoring of the whole lift operation. Our concern in this study is the recordings from the downhole equipment and for that, the surface equipment will not be elaborated in details.

The downhole equipment is suspended from the production tubing into the formation. The motor is often the last component of the equipment and it is put off just above well's perforations. The protector and intake in between the pump and the motor is also called a seal chamber usually aiming for gas separation. It is observable from the below figure that the power cable is clamped all the way to the tubing and plugged into the motor.

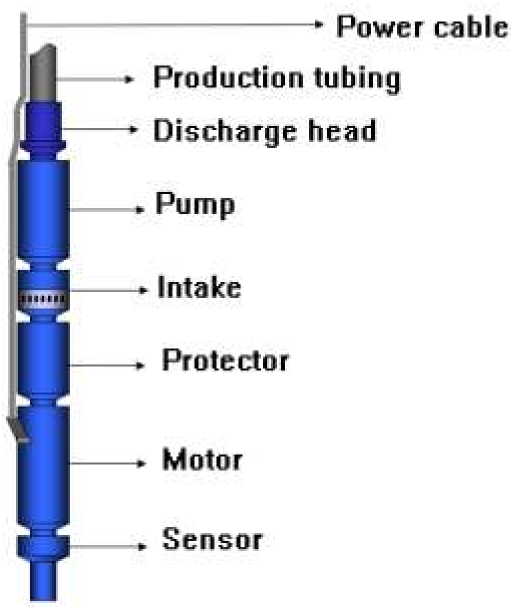

Figure 7: ESP downhole equipment design

The fluid coming out of the well flow past the motor having it cooled, it then enters via the intake which will take it straight into the multistage centrifugal pump. Each stage of the pump is composed of an impeller and a diffuser aiming in transforming the kinetic energy to an extra pressure or head that adds to the fluid at a given certain rate. This extra pressure will help the fluid to build up enough pressure to travel up the pump and therefore be lifted up to the surface and into the separator.

The whole downhole equipment is constructed at the surface and is run together into the borehole with the production tubing using a rig unit. In offshore applications, deploying ESP will be done using a standard coil tubing eliminating the need of a workover rig as moving the rig will delay production and increase costs.

The submersible centrifugal pump system used in this case study enables the investigation of the following main components of the system under different pressures and temperatures:

- The pump stage of a submersible centrifugal pump in the vertical installation state
- The rotary drive 55 kW standard electric motor
- The module enables inlet pressures of up to 40 bar and outlet pressures of up to 160 bar, as well as a temperature range from ambient temperature up to 80 ° C
- The mixing system and the inlet of the pump stage
- The control system and the outlet of pump stage

The following are the conditions at which the ESP facility used is operating:

- The mixing system enables flow rates of up to 20 m^3 / h of water, which is stored in a pressure vessel that is buffered with compressed air
- A further liquid phase with a volume flow of up to 3 m^3 / h can be introduced into the mixing system by means of a screw pump.
- As a gaseous phase, 50 kg / h of compressed air can be processed in the mixing system.
- The mixing system enables the targeted dosage of two liquid and one gas phase, as well as mixing using static mixers
- A liquid phase and a gaseous phase of compressed air can be injected in the mixing system
- The three-phase mixing is controlled by control valves at the inlet of the mixing system

- The control system at the outlet determines the counter pressure of the pump
- The default frequency of the pump drive and the control valves positions can be set individually

A heat exchange was used with the facility to dissipate the extra amount of heat generated by the pump drive to the cooling medium as the liquid flow is circulating during the tests. The ESP module is based on the power drive which includes power current, speed and torque, the suction pressure and temperature, the volume flow of each phase and the outlet conditions.

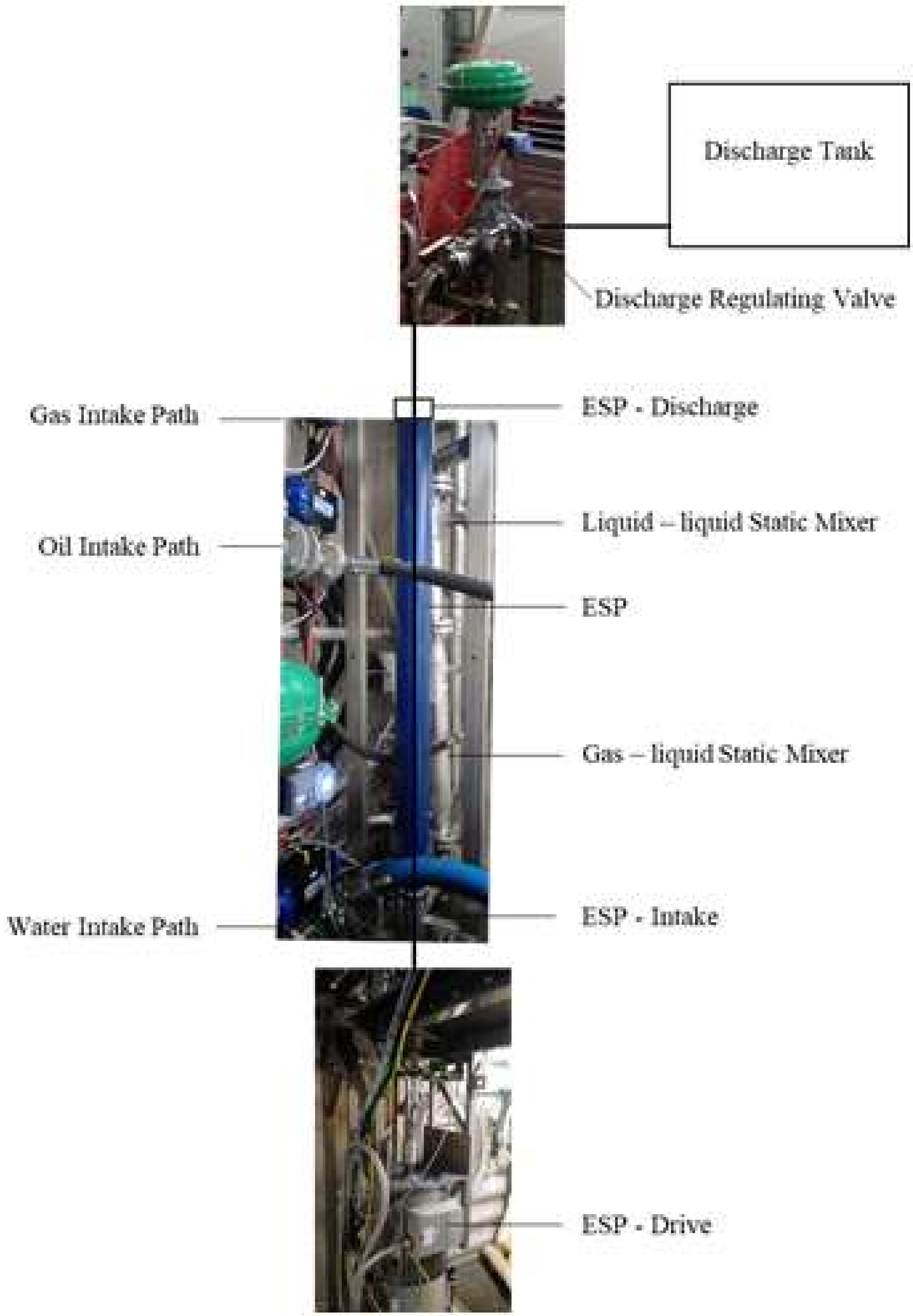

Figure 8: ESP test facility

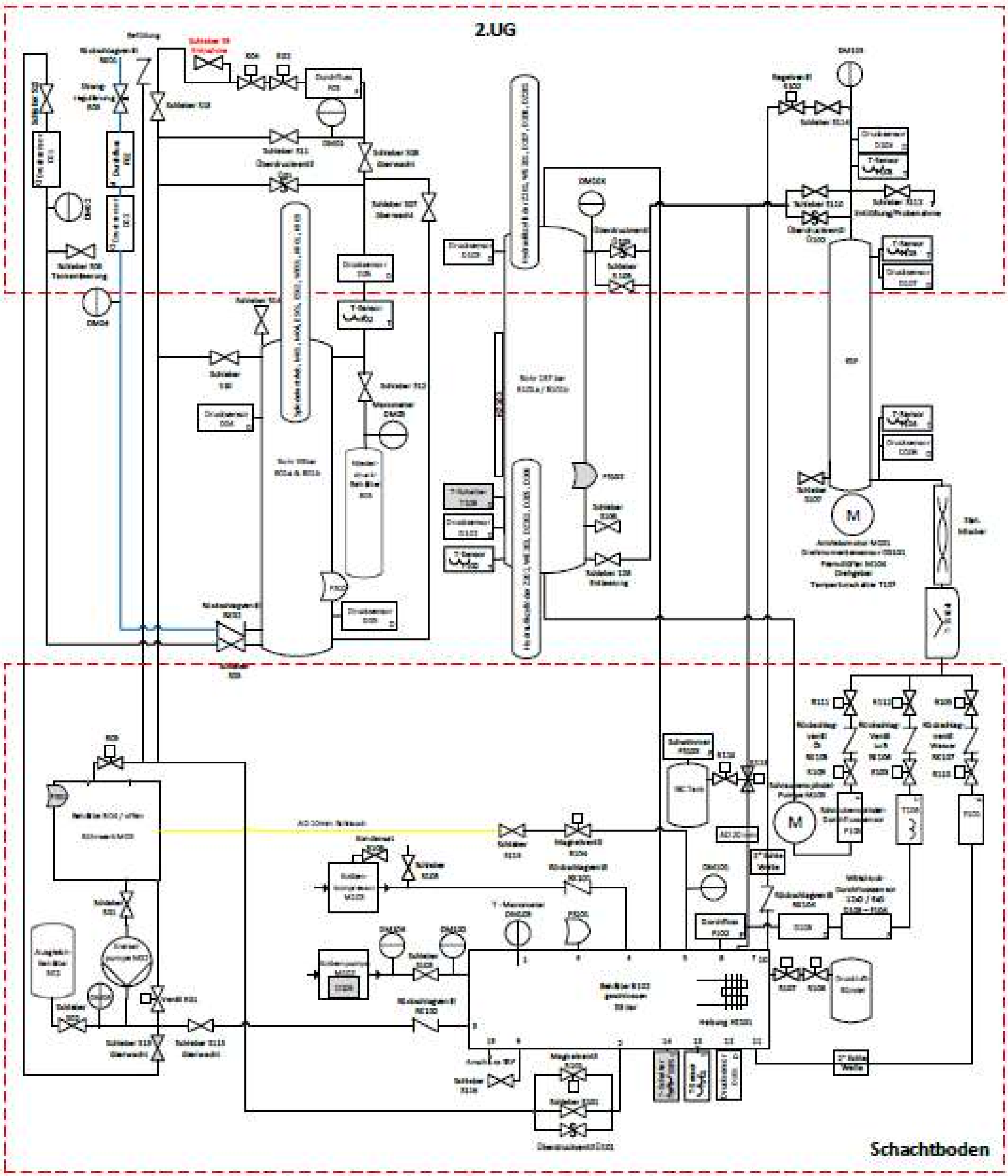

Figure 9: ESP test facility schematic

3.1. Multistage Centrifugal Pump

Design

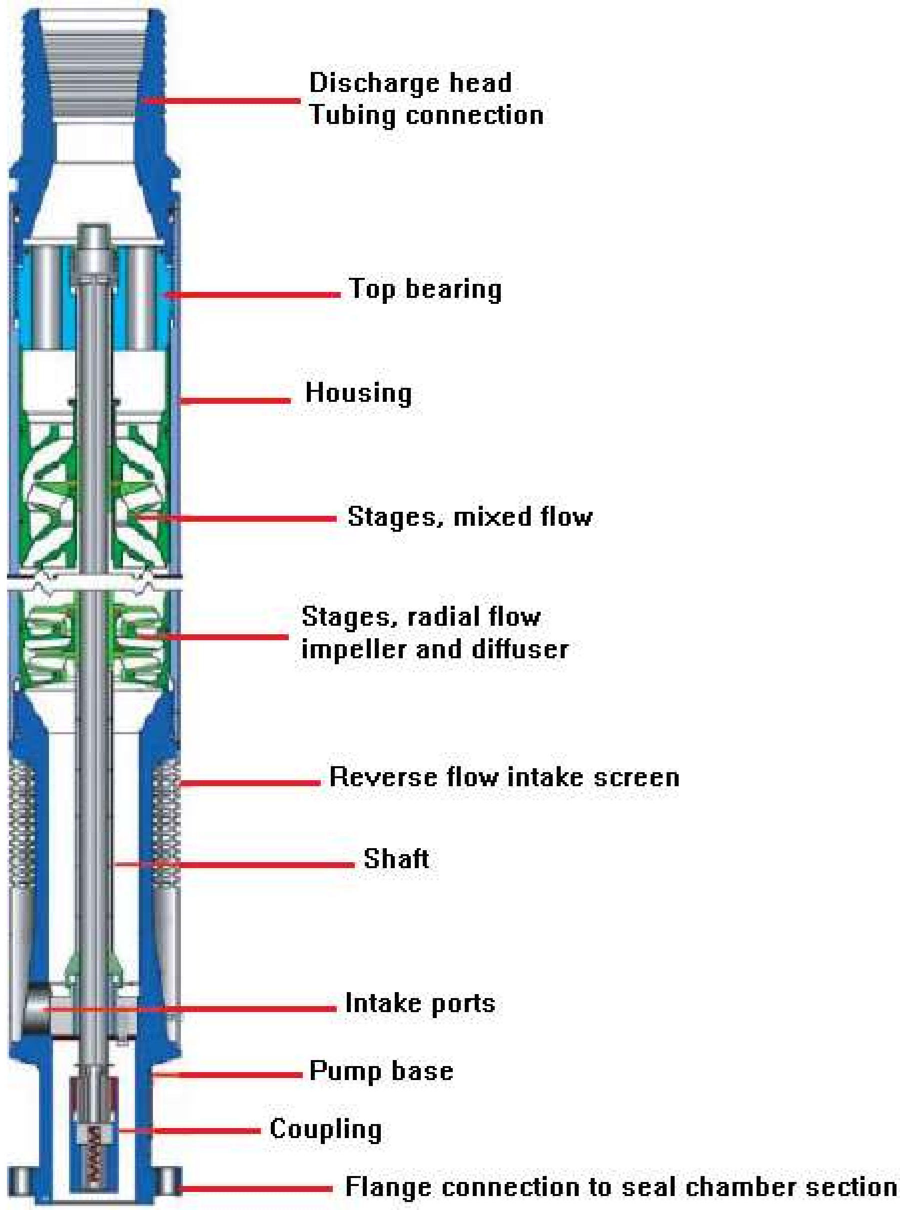

Figure 10: Multistage centrifugal pump

Figure 11: Pump stages

Centrifugal multi-stage pumps are used to lift high volumes of fluids from the wellbore. The pump adds lift pressure to the fluid hence improving hydrocarbon production. The stages of the pump are connected in series. The number of stages is assigned based in the desired rate, the wellhead pressure, the pump depth and the friction inside the production tubing. Having multi-stage pump rather than single-stage pump will give the same rate at constant speed operation but it will show an increase in pump head.

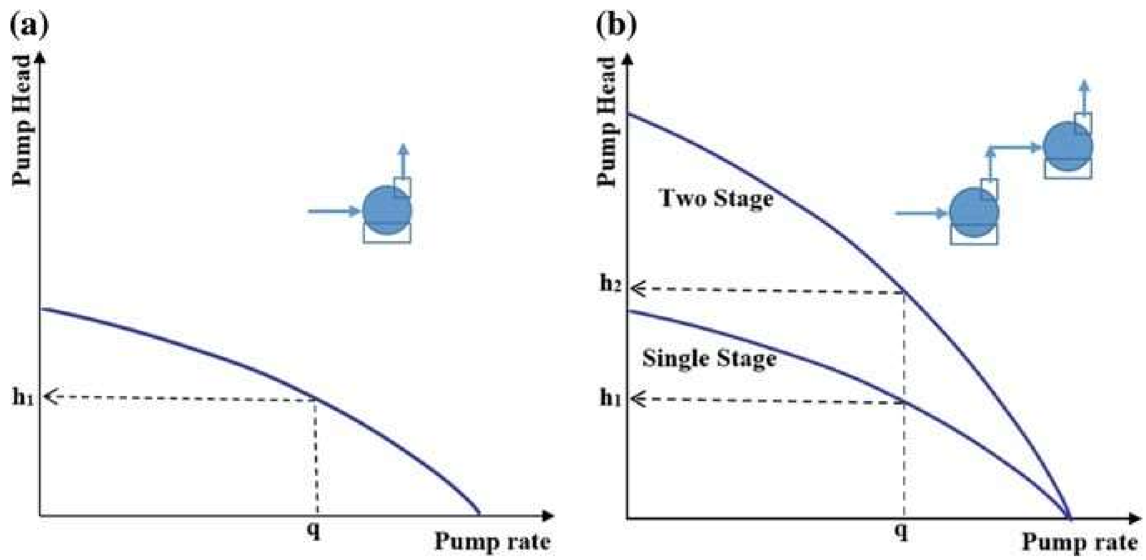

Figure 12: Single-stage centrifugal pump theoretical performance vs multi-stage centrifugal pump (2 single-stage connected in series) theoretical performance

Working principles

The pump stages are connected in series to increase pressure. Since ESP is installed right above the perforations, the multi-stage centrifugal pump provides energy, differential pressure across the pump, to lift the fluid column inside the tubing and therefore decrease FBHP. These stages are equipped with guide vane and the rotating impeller and the diffuser are equipped with a guide blading. As the fluid enters the impeller eye, the energy in form of velocity is imparted to the fluid by centrifugal force. Later, the highly twisted fluid leaves the impeller through the vanes where it becomes twist-free and enters the diffuser. The diffuser converts the energy of the fluid to a pressure and redirect it into the desired direction for the next stage. This process goes on until the fluid passes through all stages reaching by that its desired discharge pressure. The pressure increase is often referred to as the total developed head (TDH) of the pump.

The discharge pressure of the pump must be equal the OPR pressure and the intake pressure must be equal the IPR pressure. The differential pump pressure is determined by these two pressures.

The following figure will show how the OPR with pump will intersect the IP at a higher flow rate and a lower FBHP. The production liquid rate mainly depends on the ESP performance and not the number of pump stages.

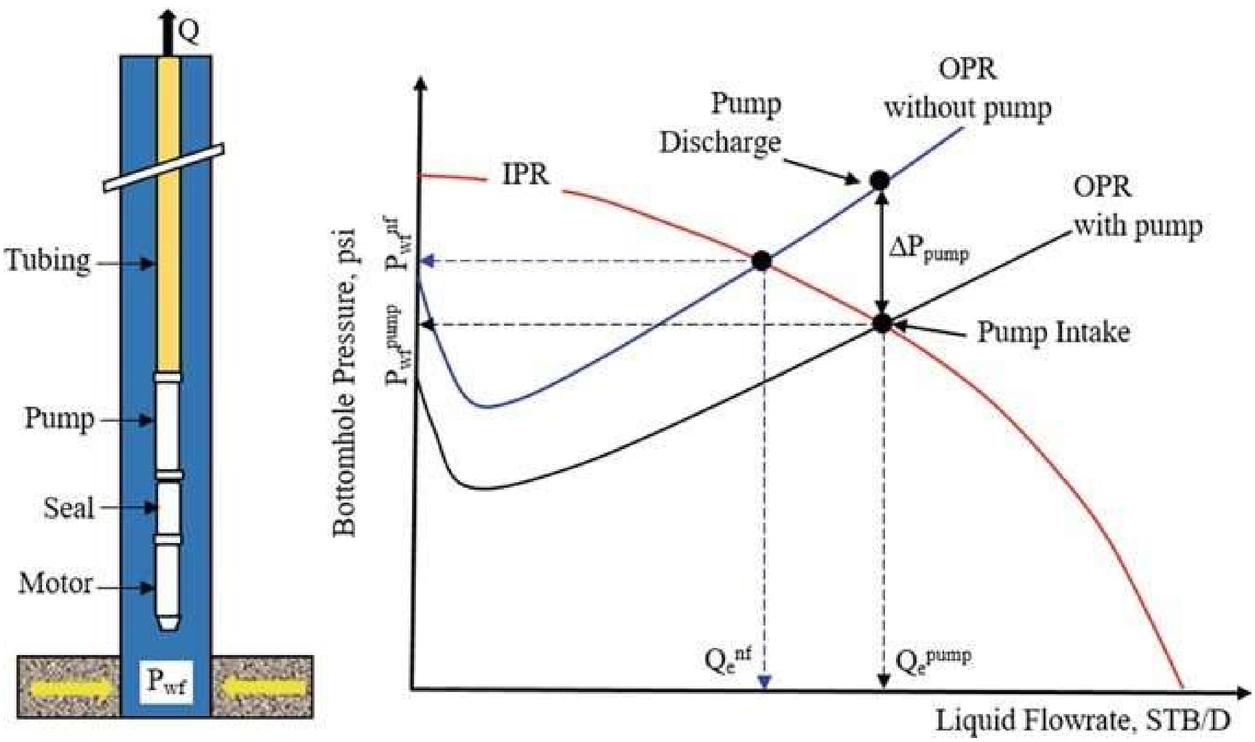

Figure 13: Working principle of ESP

Pump Head

In terms of pressure, the pump performance depends on the density of the fluid being pumped. However, in terms of head, the pump performance is independent of the density and hence independent of the fluid that is being pumped. In other words, head measures indirectly the pressure independently from fluid density. The head in meter of one pump is calculated in SI unit from the following relation:

Equation 11: Head calculation

$$H\ stage = \frac{\Delta P\ stage}{\rho g}$$

Where ΔP is the pressure gain across the stage (Pa), ρ is the fluid density (kg/m^3) and g is the gravitational acceleration (m/s^2).

The pump head in oil field is expressed in feet as:

Equation 12: Head calculation for oil fields

$$H\ stage = \frac{\Delta P\ stage}{0.433\gamma}$$

Where ΔP is the pressure gain across the stage (Psi) and γ is the fluid specific gravity (dimensionless).

Pump Performance

Pump performance is defined by a relationship between the liquid flowrate and the pump pressure or pump head at a constant pump speed. To be able to plot this relationship, the pump will be tested by water by varying discharge pressures and recording liquid flowrate. A theoretical pump performance curve was developed to replace the actual pump performance curve test as it is sometimes costly and time consuming. This theoretical pump performance curve is based on the following assumptions:

- Radial and tangential two dimensions direction
- No void spaces inside the impellers (completely filled with the flowing fluid)
- Incompressible single-phase fluid
- Symmetric velocity profile

Equation 13: Theoretical pump performance

$$\Delta P\ stage = \rho\omega^2(R2^2 - \mathrm{R}1^2) - \frac{\rho\omega Q}{2\pi h}(\frac{1}{tan\beta 2} - \frac{1}{tan\beta 1})$$

The above equation is used to describe the theoretical performance of a single stage centrifugal pump in terms of pressure and SI unit.

The actual pump head is always smaller than the theoretical one for a given pump rate due to the assumptions taken to develop the theoretical pump performance curve. In addition, leakage and hydraulic losses, which include frictional losses due to the viscous effect, fluid shock loss, diffusion loss, etc. inside impellers also participate in the pump head difference. Due to the mentioned reasons, the actual performance curve will be curved and will not exhibit a straight line.

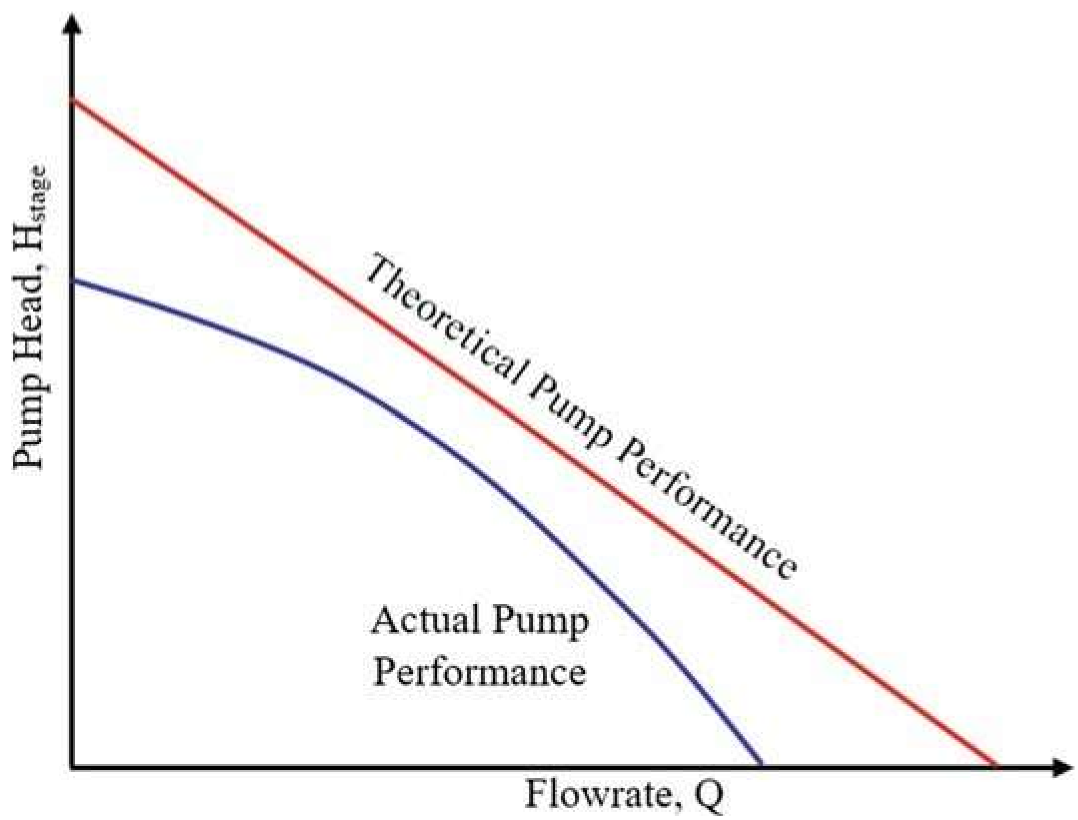

Figure 14: Theoretical and actual pump performance curves

Hydraulic Horsepower and Brake horsepower

The hydraulic horsepower is defined as the energy transmitted to the fluid by the pump. it is defined also as fluid horsepower and it is considered as the power to lift fluid volume flow rate to a specific height.

The brake horsepower is the power required to overcome all the losses and hence provide enough energy to pump the fluid. In other words, it is the power required by the pump shaft to turn.

The brake horsepower is always higher than the hydraulic horsepower and it is measured from the actual performance curve.

Pump Efficiency

The pump efficiency is defined from the ratio between hydraulic horsepower over brake horsepower. It depends on the friction losses due to fluid viscosity, mechanical losses, turbulent loss, etc.

Actual Pump Performance Curves

As mentioned before, the pump manufacturers develop the actual pump performance curve by testing the pump with water by varying discharge pressures using the control valve on the discharge line and recording the intake pressure, the brake horsepower and the discharge pressure. The hydraulic horsepower and the pump efficiency are calculated and the pressure gain detected is then converted to pump head. Under testing conditions, it is possible to plot on the same graph the following curves:

- Head vs flow rate
- Brake horsepower vs flow rate
- Pump efficiency vs flow rate

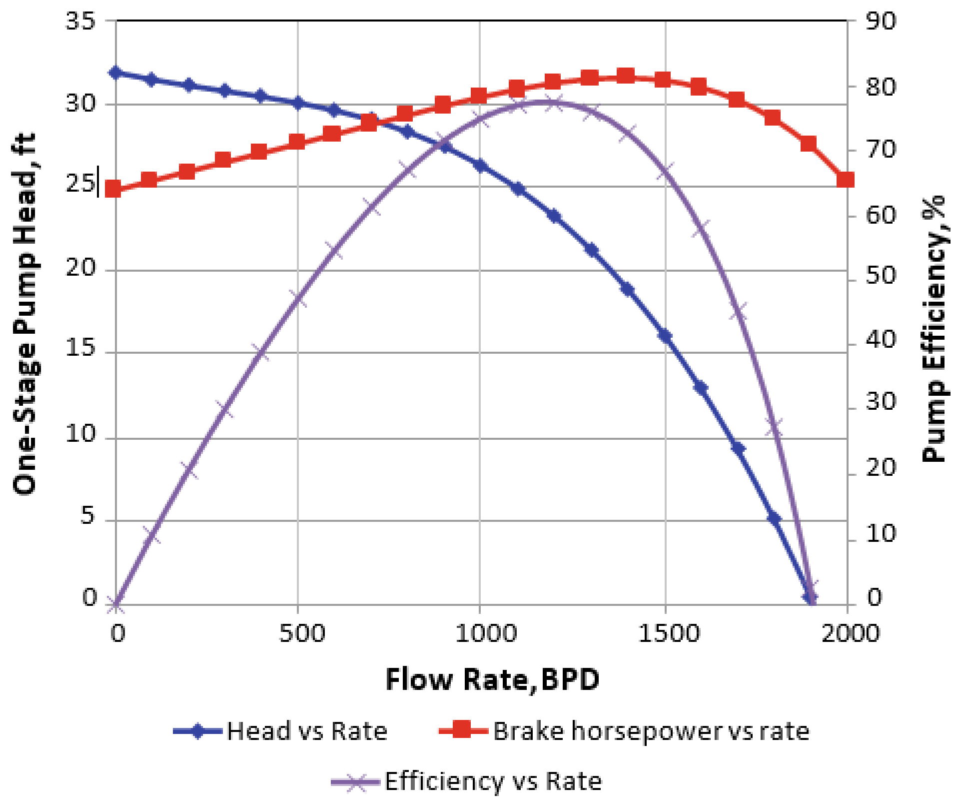

Figure 15: Actual pump performance curves

Viscous Effect on Pump Performance

Converting pump pressure to pump head takes care of fluid density. The actual pump performance developed by water testing is different than the actual pump performance when working with a viscous fluid. Operating with a viscous fluid will cause an increase in brake horsepower, a decrease in pump capacity and a reduction of head. In order to be able to predict the actual performance of an ESP handling viscous fluid, it is very practical to compare with a known actual water performance of the same pump. The three common methods to do so are Stephanoff method, Hydraulic Institute charts method, and Turzo correlation method.

Housing

The housing hold and aligns all components of the pump and is considered the pressure-containing skin for the pump.

Shaft

Through coupling, the shaft is connected to both the motor and the seal chamber. Its main goal is to transmit the rotary motion from the motor to the impellers of the pump stages. This goal is achieved by having the shaft and the impellers connected.

Pump Intake

The intake primary goal is to allow the entrance of the formation fluids from the bottom to the first stage of the pump

Impeller and Diffuser

The stages are the components of the pump that impart the fluid with a pressure rise and each stage is made from an impeller and a stationary diffuser. In a single-stage centrifugal pump, the diffuser is stationary and the impeller rotates inside the diffuser via a shaft connected to an electric motor. The kinetic energy is transmitted to the liquid entering the impeller because of the rotation. Next, the fluid leaves the impeller and enters the diffuser where the fluid energy will be concerted to pressure. This gain pressure is defined as the difference between discharge and intake pressure.

Radial or Mixed flow

ESP classification is based on whether the stage design is mixed flow or radial flow centrifugal pump. A radial flow centrifugal pump is a pump where the pressure or the head is entirely developed from centrifugal forces. The flow enters the impeller or the diffuser parallel to the axis of the shaft and exits perpendicularly to the shaft. This centrifugal pump is usually used where low-flow, high-head installation is required. The pump efficiency will be around 60% with low liquid rates ranging from 100 to 2000 bpd.

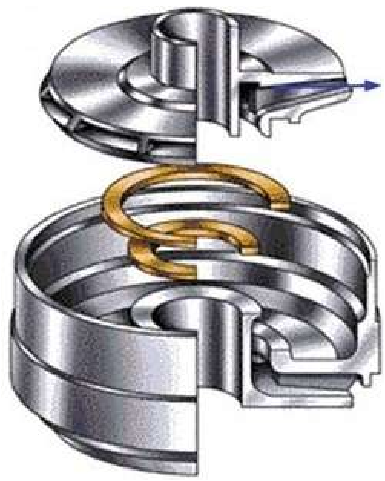

Figure 16: Radial flow stage

The mixed flow centrifugal pump is however a pump in which the pressure or the head is partly developed with centrifugal axial forces and partly by the lift of the impeller of the liquid. This centrifugal pump is used where high-flow and high-head installations are required. The flow exits the impeller at an angle less than 90° to the shaft. Opposing to the radial flow stage, this pump design is effectual with high liquid rates ranging from 1000 to 50,000 bpd with an efficiency higher than 60%. The most important feature of this centrifugal pump design is that it can handle gas and solid presence.

Figure 17: Mixed flow stage

Pump Thrust

A thrust is defined as the hydraulic force acting on the pump shaft. The thrust can be generated at the impellers and at the shaft. Both styles of stages follow a method in carrying their axial thrust. When pump thrust is high for a long period of time, bearing and mechanical seal failures can be detected along with the risk of impeller damage.

Figure 18: Impeller damage due to thrust

The impeller runs in down thrust or upthrust. the three forces involved in determining whether upthrust or down thrust are:

- Gravity, it depends on buoyed mass of the impeller
- Net force, results from the differential pressure in the pump stage
- Force from the momentum of the fluid coming into the stage and then changing direction

The pump shaft thrust is the axial force acting downwards at the shaft and is generated due to the fact that pressure at the discharge of the pump is higher than the pump intake pressure. The differential pressure acting on the pump shaft cross-sectional area observed creates the thrust force.

The Impeller thrust is generated from the force acting downwards due to the impeller's area times the differential pressure. The differential pressure is observed by an increase in fluid pressure from the intake to the discharge of the impeller due to centrifugal forces and velocity difference. This pressure increase is equivalent to the pump head. In addition, when the fluid changes its direction when hitting the eye of the impeller, assuming the fluid is incompressible, a force results acting on the impeller.

The total pump thrust is the summation of the impeller thrust and the pump shaft thrust.

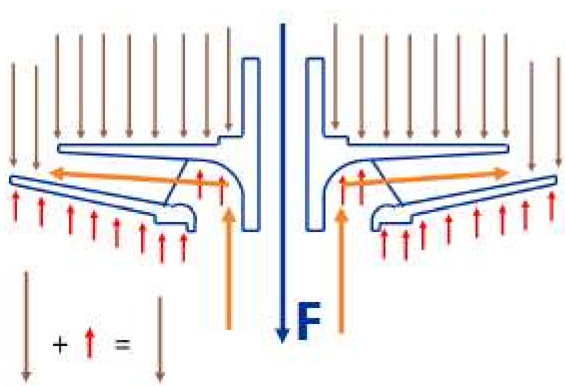

Figure 19: Forces acting on the impeller

If the pump is operating at high flow rate and a very low discharge pressure, a negative total pump thrust will be observed. Thus, the force direction will be acting upwards and the thrust is called upthrust.

In case of a positive total pump thrust, the force will be acting downwards and the thrust is called down thrust. This occurs when the pump is operating under low flow rate, a very high discharge pressure compared to the intake pressure and a high pump head.

The impeller is designed to maintain a down thrust position through its operating range in order to maintain the optimum flow path alignment between the impeller and its diffuser. Generally, high down thrust can be observed in impellers with larger diameters than smaller diameter impellers for the same flow rate due to the larger surface area.

Figure 20 represents the lift or the head vs rate calculated in feet or meters which can be produced by one stage. The highlighted area in red is the recommended operating range where pump action can be reliable. To the right, a maximum operating point at a maximum rate occurs and to the left a minimum operating point at minimum rate occurs. The best efficient point BEP is in between these two points and it is represented at the peak of the efficiency curve.

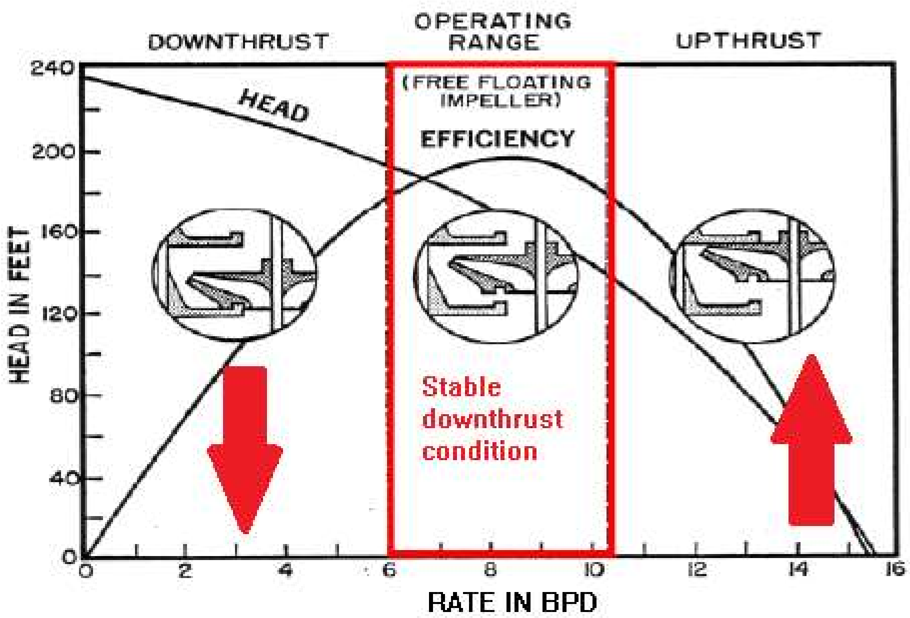

Figure 20: Upthrust and Down thrust operating conditions

Gas Interference

Gas presence in ESPs has always been vaguely handled because the visualization of fluid internal flow inside the complex geometries of multistage ESPs is very difficult. Nowadays, gas affecting pump performance became a bit clearer and gas-liquid mixture became more common for ESP applications.

Gas presence restricts the volumetric performance of the pump (the pump will not be able to give enough energy for the fluid) and leads to a decline in expected production. If the impeller becomes totally filled with gas, the lift process will be impeded which is defined as Gas Locking. In case of gas locking, the use of static or dynamic separators is essential. These separators will allow the separation of lighter gas from the liquid and pushing it to travel through the casing annulus up to the surface where it is vented out from the wellhead.

If the free gas was not properly vented out, the gas locking phenomenon will be severely observed. Gas presence will lower the fluid mixture density leading to a reduced hydraulic pressure and pump head. The discharge pressure will be low when free gas is present inside the tubing which also means that the pressure inside the pump is much less than the bubble point pressure. This free gas is escaped from the solution due to the decrease in pressure creating a phase change inside the impeller and the diffusers and will replace the liquid in pump cavities.

Another damaging phenomenon is pressure surging. Surging will cause pump deterioration, poor pump performance, pump failures, shorter pump life and vibrations. It is detected when gas pockets enter the pump at a high flow rate causing a severe flow fluctuation and pump trembling. A sudden increase in pump pressure will be caused due to the fact that the acceleration of entering gas pockets cause fluids inside the pump to slow down.

Therefore, installing downhole gas separators will help in reducing the severity of these two phenomena. It is important to note that the efficiency of gas separators is not great because a certain gas volume can still enter causing a certain degradation in pump performance.

After many studies on two-phase gas-liquid mixture centrifugal pump performance, it is reported that the pump head decreases when air injection increases. Many researchers are trying to predict the two-phase flow performance of a centrifugal pump using mathematical or experimental approaches. Yet, there is no reliable model able to predict multiphase performance of an ESP. All the models examined for this aim were able to reach some conclusions but did not provide enough information to be able to predict multiphase flow pump performance. A brief discussion on the common models is presented in Table 2:

Table 2: Common models for predicting multiphase flow ESP performance

Models	Discussion
Homogeneous model	Over prediction of the performance due to the many assumptions taken
Empirical correlations	Very limited because they were developed based on a specific experimental setup and testing conditions
Vo and Nguyen model	• Pump performance is reduced when the gas injection is increased • Higher GVF will give lower pump head • Gas-locking and surging can occur when the volume of gas is large

3.2. Seal Chamber or Protector

The seal is placed between the motor shaft and the pump shaft. It helps in preventing formation fluids from entering the motor (motor oil contamination) and can be used as an oil reserve for the motor in case the motor oil characteristics change due to temperature change. The protector also absorbs axial thrust developed by the pump and dissipates the heat generated by the thrust bearing. The seal chamber allows pressure equalization between the wellbore and the interior of the motor. The three types of seal chambers are:

The Labyrinth Seal which is designed to use the difference in SG between well fluid and the motor oil to keep them apart when technically they are in direct contact.

The Positive Seal is used when the well is deviated or when the SG difference between motor oil and well fluid is similar

The Bellow Seal is used when operating under corrosive fluids, high temperatures and gassy wells conditions.

3.3. Motor

Primarily, the motor will put out horsepower as much as the pump wants. The motor is basically used to turn the pump and its speed will vary depending on the frequency. For a frequency of 60 Hz, the speed will be constant at 3500 RPM, the voltage of the motor will vary from 200 up to 5000 V, the current from 10 up to 200 A and the horsepower from 12 HP up to 2000 HP. The motor is filled with a highly refined mineral or synthetic oil for electrical protection, lubrication of bearing and for a great thermal conductivity. As the motor works, it will generate heat that will be transferred from the oil to the motor casing. Since the motor is installed right above the perforations, the produced fluid will cool the motor as it passes along and carry the heat generated up to the surface.

The motor is designed to be most efficient at the design point. When additional load is applied, a reduction in RPM and an increase in heat will be observed. The motor speed cannot be very much low because the pump performance will decrease. It is not possible to solve this problem by increasing the horsepower because after a certain level, increasing the voltage and amperage will severely overheat the motor with no assistance.

When designing an ESP, the outer diameter, the voltage, the current and the power are the most important parameters for optimum motor selection.

Usually, larger motors are cheaper to purchase.

3.4. ESP Equipment

ESP applications may vary from known ESP installation. For instance, the lift application can have an inverting bottom-intake ESP having the motor on top, a dual system, a booster ESP for surface applications or a through-tubing conveyed ESP. ESP can be equipped with packers when there is need to isolate a certain interval area right above the ESP or when there is need to provide a positive barrier between the pressurized wellbore fluid and the area above the packer to diminish corrosion to the casing.

3.5. Power Cable

The power cable is run from the junction box at the surface, through the wellhead and then all the way to the downhole motor. It is principally used to transmit electric power from the surface to the motor and to transmit signals, mainly temperature and pressure, from the borehole up to the surface. The power cable is clamped to the production tubing in between the wellhead and the ESP and plugged in the motor. The power cables have usually small diameters, they can be flat or round and they consist of five main components: a conductor made of copper wires, an insulation material, a barrier jacket, a jacket material and a steel made exterior armor.

The conductors, are responsible for electrical properties and they are insulated by the insulation material that protects the conductor wire. The insulation material is covered in a barrier jacket. The jacket material is made of rubber and is specially designed for protection against any physical damage. The exterior armor holds it all together and serves as an extra protection against temperature, chemical corrosion and mechanical abrasion.

3.6. Downhole Sensors

The downhole sensors are very important to record discharge and annulus pressures, motor and annulus temperatures, vibrations, current leakage and cable integrity.

3.7. ESP Design

The steps of ESP design include:

1) Basic data collection

Well data: casing size, casing weight, tubing size, tubing weight, completion type, TVD, measured depth, dog leg severity, etc.

Production Data: desired production rate, GOR, WC, BHT, surface fluid temperature, WHP, separator pressure, maximum surface pressure, etc.

Formation fluids: reservoir pressure, BBP, SG, oil API, oil viscosity, etc.

Other data: sand production, depositions, solid presence, corrosion, etc.

2) Pump and motor outer diameter selection and pump depth determination

The inner diameter of the production casing string will determine the maximum pump and motor outer diameter.

3) Selecting pump depth

It is recommended to install ESP from 100 – 500 ft above perforations in both vertical and horizontal wells. Around 500 ft of fluid should be over the pump to carry the heat generated and make sure the motor is cooled.

4) Analyzing well flow capacity from IPR and OPR

The well flow capacity is illustrated by IPR and OPR which are a representation of the flow inside the reservoir and the flow in the tubing and surface flowlines. From IPR and OPR, an analysis can be performed to determine which ESP is need to achieve the desired production liquid flowrate.

From the graph representing the operating point of the centrifugal pump and even though the pump is considered applicable when having some head at the target flowrate, it is not necessary that its selection is a good choice. The pump operating should not be too far on the right or the left on the operating point graph for an efficient choice.

5) Select ESP

When designing an ESP, many factors regarding the downhole pump selection should be taken into consideration. These factors include most importantly pump capacity, total pump head, pump type and pump outer diameter. Also, the pump design also depends on IPR, OPR, formation fluids density and viscosity, production casing inner diameter, GVF, sand concentration and corrosive fluids.

Proper ESP sizing helps in achieving a long run life. ESP should be sized and chosen to operate within the recommended flow range.

6) Gas and viscosity effects on pump selection

It is important to perform a gas calculation to determine the volume of free gas at the intake prior to selecting because free gas presence affects pump performance.

Higher viscosity will impact the OPR and contributes to a high friction.

7) Select motor

The selection process of the motor is based on the required power to run the ESP, the protector and the gas separator. It is recommended to select the motor and the pump from the same manufacturer.

8) Select electric cable

Selection of the appropriate power cables (round, flat, protection, cable materials, length, size) is dependent on the desired voltage and amperage that need to be run all the way down to the bottom. Geometry of the well and the bottomhole conditions like temperature, pressure and corrosive materials should be taken into consideration. Clearly, high pressure and high temperature conditions require stronger cable construction.

9) Select gas separator

A gas separator will be needed for a free gas volume greater than 10%. The separation inside the gas separators is based on centrifugal forces. With a specific design, the gas separator leads the liquid to pump intake and the gas into the annulus where it will be vented at the surface.

10) Select surface equipment

3.8. Troubleshooting and Failures

Figure 21: Failures

Table 3: Troubleshooting and Failures

Problem	Causes			
Pump problems	High temperature and pressure	Corrosive produced fluid	Human error	Mechanical problems due to shaft vibration
	Improper sizing of ESP will cause a running outside the operating range and pump wear	Inaccurate fluid data	Poor operating practices or unexpected change in the operating environment	Gas locking

	High fluid viscosities increasing friction losses	Sand abrasion	Foreign material production	
Motor burn or fail	High temperature and pressure	Overloaded/underloaded operating conditions	Improper ESP design and gas locking	Paraffin or asphaltene deposition
	Heat transfer for the motor is prevented leading to a heated motor or low velocity of fluid passing by the motor	Severe well conditions	Inadequate cooling	Corrosive, erosive and abrasive environments
Cable problems	High temperature and pressure			
Pump not running	More pressure required to keep gas in solution at pump intake	Low casing pressure	Open casing valve to relieve	Excessive operating temperature
No production or production below expected	Total pump discharge head is not sufficient	Tubing leak	Obstruction in flow line	Broken pump shaft
	Worn pump	Leaking casing check valve	Flowline leak	Fluid properties variation

	Well productivity is less than pump design capacity range			
Undercurrent	Total head of pump not sufficient for the operation	Well pumped off	Pump gas locked	Surge of primary power system
	Broken pump shaft	Tubing leak	Plugged pump	Excessive casing pressure
Overload	Debris or solid in system	emulsion	Worn pump	Change in fluid properties
	Locked pump	Electric fault in system		

Chapter 4: Case Study and Methodology

1. *Introduction*

Reservoir surveillance is usually established by the measurement of flowrate on a monthly basis using a test separator. In the field rarely multiphase flow rate measurement systems are installed due to many restrictions including expenses, remote locations, logistical challenges, etc. So, the flow rate is measured at the processing facility after fluid is leaving the separator. Usually, several wells produce in the same separator. Thus, it is difficult to assign production rates to individual wells. Having a model that allows rate prediction, based on recorded pressures, torque, etc. would be very helpful. Being able to monitor ESP data, a solution to reservoir response, early trends for spotting a well test quality can be achieved.

The tests were performed in the laboratory of University of Leoben on an ESP facility built to carry out research. Several multiphase (compressed air, synthetic oil and water) tests were made on the facility, numerous intake and discharge pressures, RPM, rates, etc. were tested and the flow rate of each individual phase was measured at the entrance of the pump.

This case study presents a method for obtaining accurate liquid flowrate and water cut trends based on data recorded from an ESP test facility.

The method described in this case study for calculating liquid flowrate is based on a linear equation that can be resolved for the rate. The principle of the equation is that the power absorbed by the pump is equal to the power generated by the motor. Regarding the water cut calculation, a measurement of the production tubing differential pressure is applied to provide density which is subsequently converted to water cut. The mentioned two calculations are based on analytical equations that yield great repeatability and confidence as they ensure the respect of physics at all times. The use of such analytical equations is much better than the use of analogous methods which are based on artificial intelligence and correlations. The full production history and well performance are captured thanks to a measurement metrology provided by the use of real-time data taken from permanent downhole gauges and ESP surface equipment in the algorithms. Moreover, a worth mentioning advantage of the method is that the need to mobilize testing equipment to well site is eliminated which consequently reduces the costs, the flaring and the HSE risks associated with operations. The new technique presented in this part eliminates the necessity of physical measurement of flowrate or fluid specific gravity, takes into consideration ESP and well performance over time, and provides continuous calibration of flowrate models. When applying this method for flowrate calculations, a checkup is needed at least once each year by using a test separator to validate and verify the liquid rate and water cut calculated. The methodology presented offers the possibility of calculating liquid flowrate and water cut trends with high frequency, resolution and repeatability which will benefit in cost savings and information quality enhancement. Also, the proposed real-time algorithm gives the possibility of determining PI and drainage area reservoir pressure over time.

1. *Problem Statement*

In some difficult locations, physical measurements of flowrate are done once per year and sometimes never. A separator or a multiphase meter must be mobilized to the well site for testing operations which might take several hours or days depending on the production duration and completion.

In this case study, the tests were available over a period of 4 months 18 days and each test is planned to evaluate the proposed flowrate calculation method. The ESP is equipped with a gauge and a real-time data transmission. The data processing is accessed by two possible ways:

a) Real time processing using a flowrate calculation engine as shown in Figure 22

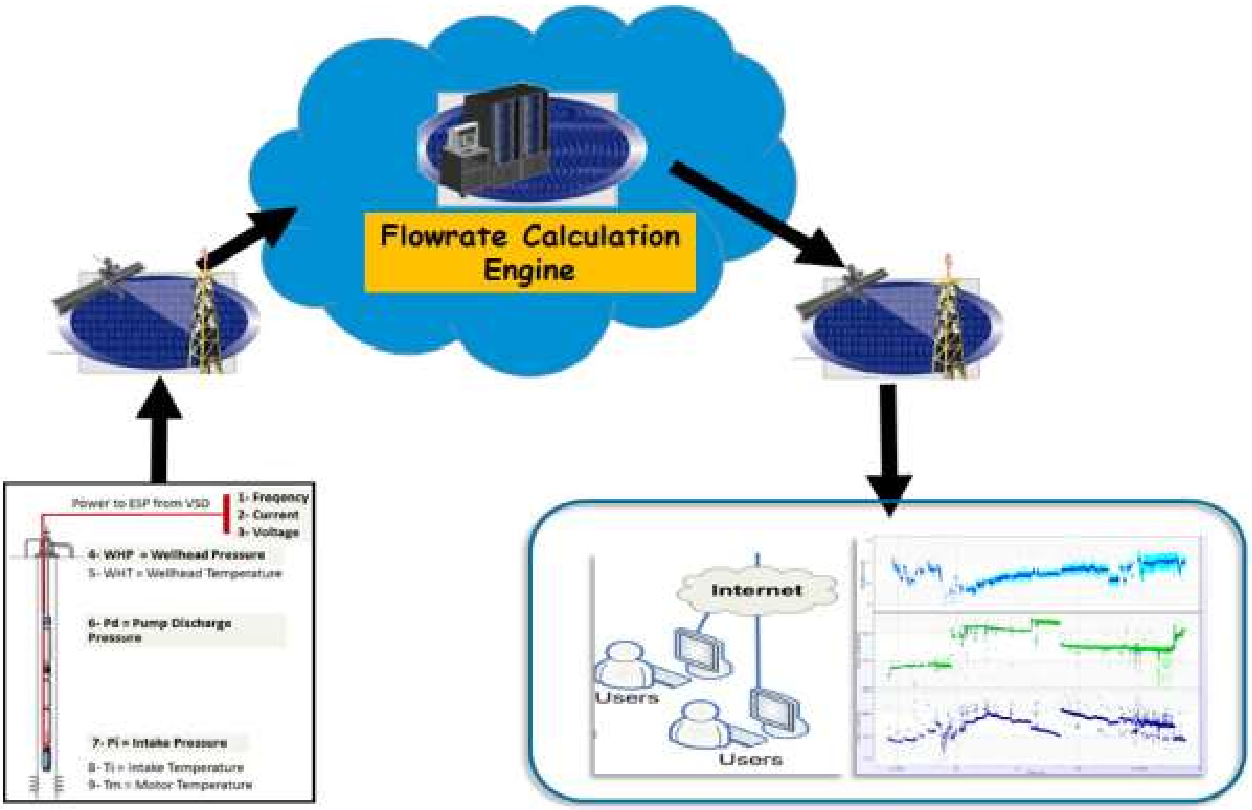

Figure 22: Real-time data delivery and processing

b) Data is downloaded for visualization and processed: frequency, voltage, temperatures, pressures and measured flowrates are plotted over the production period.

In the lab, a series of 32 tests were carried and data was recorded for each second. The advantage of testing on a laboratory facility is the possibility of varying in valve openings and ESP parameters to test outcomes for numerous conditions and variations and thus reach certain conclusions. Usually, when applying the method of flowrate calculation on an actual well (not in lab), not only the ESP power consumption, ESP operating point and ESP condition monitoring are calculated, also the evolution over time of PI, drainage area pressure, depletion and reserve calculations can be estimated for the purpose of traditional surveillance that is supported by the flowrate calculation. Therefore, besides the importance of being able to calculate the flow rate with high resolution, frequency and repeatability, monitoring activities are supported due to the flowrate calculation method.

2. *Available Measurements of the Case Study*

Many parameters that can be used for the calculation were recorded in real-time and can be deployed for the ESP facility. The ESP intake and discharge pressures are measured from downhole gauge equipped with the ESP, the THP is measured from the wellhead gauge and the current, voltage and frequency are measured from the variable speed drive (VSD). The data are provided with high frequency SCADA to pursue the aim of measuring flowrates from an available ESP instrumentation. Other parameters such as the motor temperature, acceleration and fluid intake temperature were also measured but they are not applied directly in the calculation. Table 4 represent the most important available real-time input data plotted over the production period:

Table 4: Available real-time data from downhole gauge and VSD

Pump Intake Pressure Pi	Downhole gauge equipped with the ESP

Pump Discharge Pressure Pd	
THP (3m above pump)	
Water flow rate and the pump intake	Flow meters at the intake of the pump
Oil flow rate and the pump intake	
Gas flow rate and the pump intake	
Torque, current, power	Variable speed drive VSD
Frequency	

The data frequency is very important to capture the trend of flowrate and pressure during the production period. The flowrate of water, gas and oil for each test are plotted with respect to the frequency over the total testing period.

Table 5: Data Processing

ESP start date	16 October 2019
End date of data available	05 March 2020
Number of tests	32 tests
Testing days	22 days

The characteristic curve of the pump facility used to carry-out the tests and the key parameters for ESP are presented below.

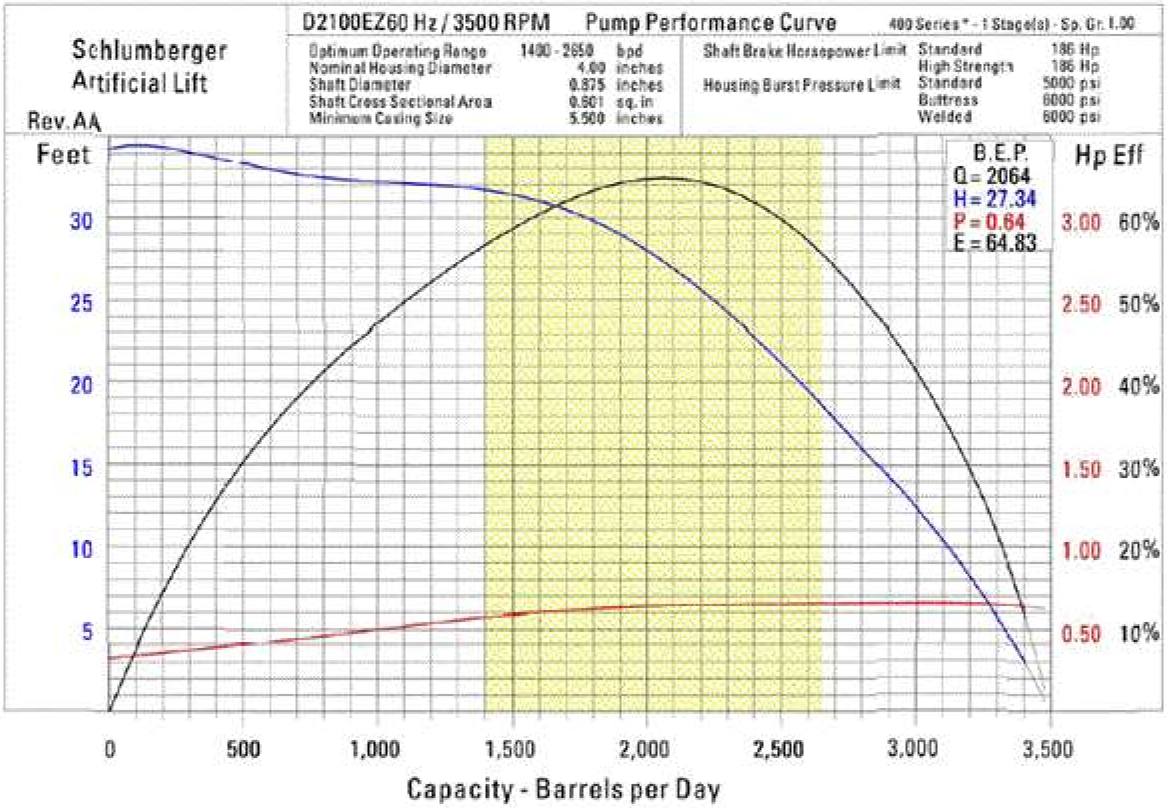

Figure 23: Pump Performance curve

From the pump performance curve given above, the BEP is given for head of 27.34 ft, flowrate of 2064 BPD, power of 0.64 HP and a pump efficiency of 64.83%.

Table 6: Completion key parameters summary

Pump D2100EZ Schlumberger Artificial Lift	Series: 400 Stages: 82 Minimum casing size: 5 ½ in OD: 139.77 mm Weight: 331.9 lb	Optimum operating range: 1400-2650 bpd Nominal housing diameter: 4 in Shaft diameter: 0.875 in SG = 1

	Carbon steel ES-TT Frequency: 60 Hz	Shaft cross sectional area: $0.601\ in^2$

3. *Liquid Rate Calculation*

The base of the liquid rate calculation is described in the power equation taken from Camilleri et al. five papers published in 2010, 2011, 2015 and 2016. The method experienced applications on conventional wells in 2011 (Camilleri and Zhou, 2011) and recently on an unconventional well in 2016 (Camilleri et al. URTEC 2016). The power equation is built on the principle that the power absorbed by the pump is equal to the power generated by the motor. The formula is detailed as the following:

The Power Equilibrium Equation of an ESP is a method intended to calculate the liquid flowrate Qp. The torque and speed of the pump absorbed power in an ESP is considered equal to that generated by the motor at all times. The equation is presented as the following:

Equation 14: Power Equilibrium Equation

Power absorbed by the pump = Power generated by the motor

$$\frac{DP \times Q_p}{58847 \times \eta_p} = \frac{V_m \times I \times PF \times \eta_m \times \sqrt{3}}{746}$$

The flowrate, Qp, is the only unknown and is then calculated as the following:

$$Qp = \frac{Vm \times I \times PF \times \eta\mathrm{m} \times \sqrt{3} \times \eta\mathrm{p} \times 58847}{746 \times \Delta P}$$

A more simplified form of Equation 14 is given:

Equation 15: Simplified form of the power equation

$$\frac{DP}{Power} = \frac{\eta_p}{Q_p}$$

The simplified form of the power equation is more useful as $\frac{DP}{Power}$ is measured from real-time data and $\frac{\eta p}{Qp}$ is obtained from the pump characteristic curve.

Camilleri presented in his 2013 paper a more detailed way to resolve this equation. The power is calculated in horsepower using all the following constants associated with oilfield units:

Table 7: A review of the meaning, the source and the assumptions taken of each term in the power equation

DP	• Differential pressure across the pump; difference between intake and discharge pressures • Measured in (Psia) • Intake and discharge pressures are measured from downhole gauges in real-time
η_p	• Pump efficiency • The pump efficiency is taken from a catalog or from test curves because it can be measured directly
I	• Motor current • Measured in (Amps) • Measured by the VSD • The value taken from the VSD is multiplied by the surface transformer ratio to give the downhole current
Vm	• Downhole motor voltage • Measured in (Volts)

	• Only motor surface voltage can be measured and the measurement is done via the VSD controller • Divide the surface measurement by the transformer ratio to obtain downhole voltage • Subtract the voltage loss in the power cables from the surface voltage measured by estimating cable resistance properties and the measured current
$\eta_m \times PF$	• Product of motor efficiency and power factor • The values cannot be measured for the current case study • Another possibility is the measurement of PF with additional electrical instrumentation at the surface which can be considered on other wells • For all loads and voltages, the motor model calculates $\eta_m \times PF$ while ensuring that the liquid rate was valid at low startup frequencies when the load factor is low • The motor model is based on motor laboratory test data that can calculate the product

The power equation provides a unique solution across the full flowrate of the pump curve, ensures that any change in measured data will translate into change in flowrate, is based on the fact that current is proportional to flowrate and is independent of specific gravity (SG). All of these benefits made the power equation the chosen method. An elaboration of each benefit is provided next:

A. The traditional pump rate calculation method does not provide a unique solution across the range of the pump curve and that is what makes the power equation method superior. The traditional method simply uses the head vs flow curve and measures differential pressure. In this method, it is impossible to obtain a unique solution for flowrate by measuring the differential pressure at flowrates are below the BEP. This is due to the fact that some pumps exhibit a curve shape that is either saddle or flat which are represented in Figure 24

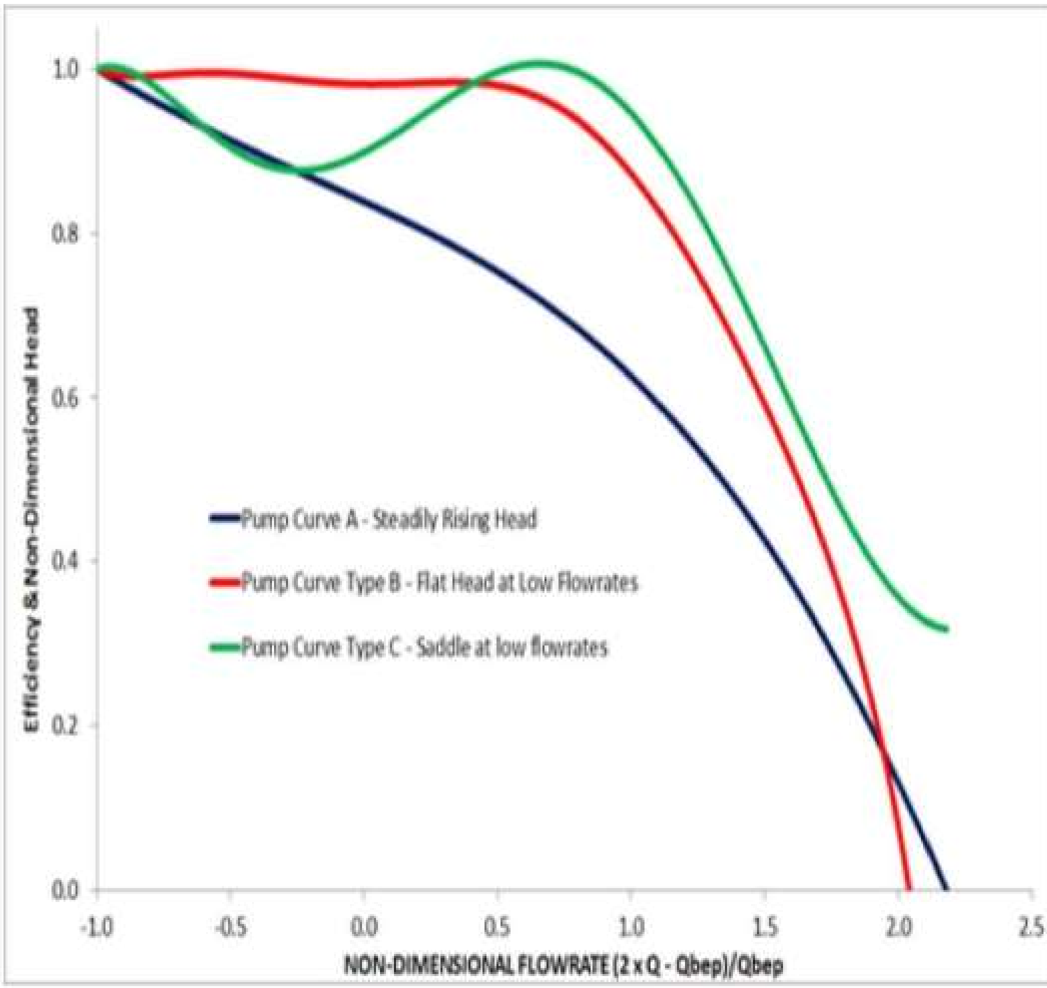

Figure 24: Illustration of the three main head-flow curves found in industry showing NON-UNIQUE flowrate solution when using the traditional method

However, the power equation shows a unique solution for the same three plotted head-flow curves. In the power equation method, a unique solution, for any measured ratio of differential pressure to power DP/Power, across the full range of a pump is established irrespectively from the type or the shape of head vs flow curve. The ratio η_P/Qp is plotted against the normalized flowrate. Note that in this case study the ESP is considered operating above BEP, however, this is usually unknown before performing the analysis. For that matter, a generalized solution applicable in any well condition was required.

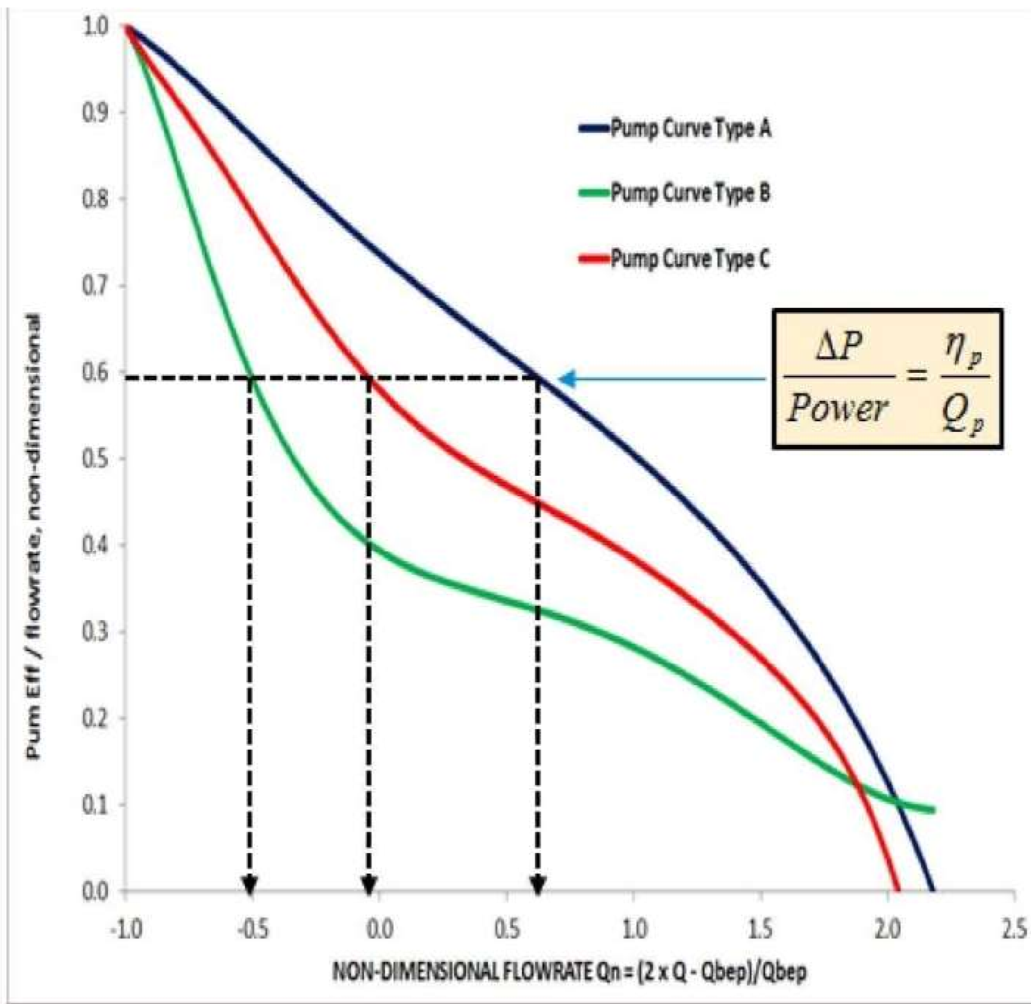

Figure 25: Illustration of the three main head-flow curves found in industry showing UNIQUE flowrate solution when using the power equation method

B. The power equation ensures that any change in measured data will translate in a change in flowrate. This is due to the use of analytical equation derived from first principles rather than using correlation or neutral networks. If the power equation is respected by a certain well, a flowrate vs time curve can be plotted that can show when the flowrate is decreasing or increasing. This captures the liquid rate trend even when the model is uncalibrated. In the absence of pump performance degradation, the pump efficiency curve remains unchanged. Therefore, when calibrating the model, the validity can be extrapolated to other pump OP due to the fact that the physics are respected at all times when performing the calculation. Yet, in case a deterioration in pump performance is detected, the recalibration of the model is a must. One added benefit for the power equation method is that the flowrate resolution can be calculated by deriving the analytical equation mathematically in function of the instrumentation resolution. The flowrate resolution is essential for measuring the change in flowrate and therefore its determination is valuable.

C. The required power by the pump is the "action" and the current is the "reaction". This statement is an expression of the idea that the power equation relies on the concept that current is proportional to flowrate. ESP is considered to have low inertia which helps the current in almost being instantly able to react to any change in flow rate. For this reason, this property suits ESP very well.

D. Being independent of fluid SG is an important aspect since changes in water cut are unknown due to phase segregation at start-up and due to the variation of WC and GLR in tubing and pump during production. The power equation is independent of the fluid SG which makes this feature not only beneficial in assessment of PVT uncertainties of a well but also because the liquid rate becomes independent of water cut which in many cases are very difficult to estimate.

To summarize, the power equation enables the calculation of liquid flowrate when assuming that the pump power which is a function of flowrate, pump efficiency and differential pressure is equal to the motor power that is function of downhole current, motor efficiency, motor voltage and power factor.

The gauges are installed on many currently active wells to record a range of data that includes intake pressure, temperature and discharge pressure. These additional data are very essential despite the fact that they add cost for gauge. They serve in calculating ESP flowrate in real time, generate water cut trends and monitor motor cooling.

Besides all the mentioned above benefits, liquid flowrate calculation from the power equilibrium equation provides the ability to capture transient and steady state conditions. It also provides real-time pump operating point BEP. The BEP is the optimum range for pump operation. Engineers tend to keep the pump functioning inside the BEP range where less mechanical wear, pump degradation and power consumption are likely to occur.

The power equation is subject to calibration to provide more accuracy when working on actually producing wells. This is due to the changes in each well where the analysis cannot be carried on over a very long testing period. Instability will results making the calibration of the model a main need. Also, a verification of the calculations and data should be continuously done with the traditional flowrate measurement methods to be able to compare the results with the actual well performance. Therefore, in real operations, recommendations over ESP design are a main discussion for the purpose of improving operational stability based on the calibrated model. Yet, the main benefit of the method in our case study is that it was able to provide liquid flowrate trend even when the model is uncalibrated making the observation of flowrate increase or decrease identifiable and the ESP and reservoir behavior diagnosable.

The method was tested based on an ESP laboratory facility. But the benefits such method when working on actual producing wells are numerous:

- The liquid flowrate calculated from the power equation eliminates the need of depending on WC and PVT properties and focuses on providing the downhole average flowrate through the pump. This will eliminate the need of doing surface corrections for the measured flowrate by a test separator to the downhole conditions using the Formation Volume Factor effects. Therefore, head degradation generated due to the operation below the minimum recommended flowrate which results in an increase in free gas amount.
- Further ESP installations will be dependent on the analysis of the method to know if more stages will be needed to keep ESP operating in the BEP range.
- ESP optimization is done by analyzing different strategies when operating in multiphase flow conditions and a view over the number of stages, tubing size, pump geometry, etc. can be evaluated based on the calibrated model to reach the highest efficiency.
- The power equation model provides high repeatability and resolution of liquid flowrate trends compared to traditional flowrate measurement tools.
- Production changes even at very low rates can be seen and optimized when plotting the downhole measurements together.
- When calibrated, the trends can monitor well performance as they are taken with high resolution in real-time.
- The flowrate trends generated from the described method are accurate even if pump is subjected to some wear
- The rebuilt of flowrate on numerous wells during the pat few years documented an effective completion.

- ESP serves as the optimum artificial lift method in wells with high water cuts to improve recovery and predict water cut trends.
- This method reunites each person with his own expertise to implement a model in a collaborative workplace where no geographical challenges exist.
- The ability to identify small changes in flowrate is essential for better planning of well tests because ESP flowrate start-up and surge due to high gas to liquid flow can be observed.
- Plotting gauge data enables the possibility to surveil motor cooling process and fluid intake pressure variations. A drop-in liquid rate or an increase in free gas presence could lead to an insufficient motor cooling. This can be illustrated by plotting the calculated flowrate from the power equation method.
- A drop in reservoir pressure could lead in a drop in PI and therefore a skin increase. This drop cannot be captured by a test separator.
- A difference in flowrate trends generated from the power equation method and the test separator method can be explained by the inability of tests separator in capturing transient disturbance effects in the well that can be generated if ESP is numerously turned on and shut-off.
- The power equation method provides the possibility of calculating, without the need of changing frequency, the necessary voltage amount from motor generating power that can reduce the motor consumed power and operating temperature.
- The rate normalized pressure drop ($(P_i-P_{wf})/Q$) that can be generated from the power equation can be plotted versus time to estimate PI, skin and reserves.
- The power equation generates a flowrate trend (not an absolute flowrate value) that gives a slope from the rate normalized pressure drop versus time plot. This slope can identify

whether the flow regime is bilinear, linear or boundary dominated flow. This graph also shows the importance of liquid rate calculation at high frequency compared with episodic measurement well tests. The traditional test separator cannot provide the necessary frequency to identify flow regimes.

- Reserves estimates can be obtained from history matching simulation of measured pressures and flowrates. The technique and formula are more detailed in Camilleri et al. (2015 and 2016) papers.
- The pressure transient analysis can be possibly estimated when having a high frequency flowrate by evading build ups.
- Drainage area pressure and flowrate variation trends can help in calculating IPR and PI. The uncalibrated model can provide reservoir flow regimes and fracture communications by plotting on a log-log graph the rate normalized pressure drop ($(P_i-P_{wf})/Q$) versus elapsed time.
- The virtual flowrate predicting tool can serve many wells which makes the process more cost efficient.
- ESP operating point is continuously estimated in real time when having a liquid flowrate calculation model.
- Reserves estimate became possible because of the high frequency calculations.
- The liquid flowrate calculation is enough to calculate the inflow performance of a well using the mathematical model of this case study. This makes the calculation independent from water cut calculation.

4. *Water Cut Calculation*

The calculation of pressure drop in the production tubing between pump discharged pressure and THP provides a measurement of mixture density which can be translated into water cut based on the in-situ oil and water densities. The series of equations used is presented next as an illustration of the calculation where uncalibrated WC trends plot tubing differential pressure with a good representation. The WC calculation is demonstrated on ESP wells located in Saudi Arabia (Sultan et al. 2012) and field tested as documented by Camilleri and Zhou in 2011.

The following equation expresses how the average mixture density in the production tubing above ESP is calculated as a function of the differential pressure between the pump discharge pressure and wellhead pressure in order to estimate WC.

Equation 16: Relationship between mixture density and outflow pressures

$$\frac{Pd - Pth}{gh} = q_{liquid} \times H_L + \rho_{gas} \times (1 - H_L) + friction$$

Friction must be taken into consideration along the length of the tubing in order to achieve a single calibration over an extensive range of flowrates. Using the above equation, the change in density can be related to a change in WC in environments where the average tubing holdup change is limited. For such a model, once calibrated against ideally measured water cut using a multiphase flowmeter, trending water cut with time turn out to be possible. For this method to be applicable, THP and pump discharge pressure should be measured in real-time. In case of slugging detection in tubing, the high frequency data can be able to capture pressure oscillations. After neglecting the pressure drop in gas phase and using the equation above that describes the relationship between the average mixture density and outflow pressures, WC is obtained as the following:

Equation 17: WC calculation

$$WC = \frac{\rho_{liquid} - \rho_o}{\rho_w - \rho_o}$$

The method and calculation methodology presented above was studied by Camilleri et al. assuming constant hold-up. For well having a high WC and low GOR, this assumption can be practical.

5. *Analysis and Observations:*

5.1. **Analysis:**

Since the flowrate of each phase is measured at the intake of the pump and plotted against the frequency over the whole testing period, each specific test shows how the flowrate measured at the intake differ from the one calculated at the discharge.

In this section, a brief presentation of the measurements of water, oil and gas flowrates recorded at the intake of the pump and the liquid flowrate and water cut calculations done using the power equation method.

Test 1: 16/10/2019:

This is the first test done on the facility. The gas valve is at 97% and the oil valve is fully shut. The produced fluid is water.

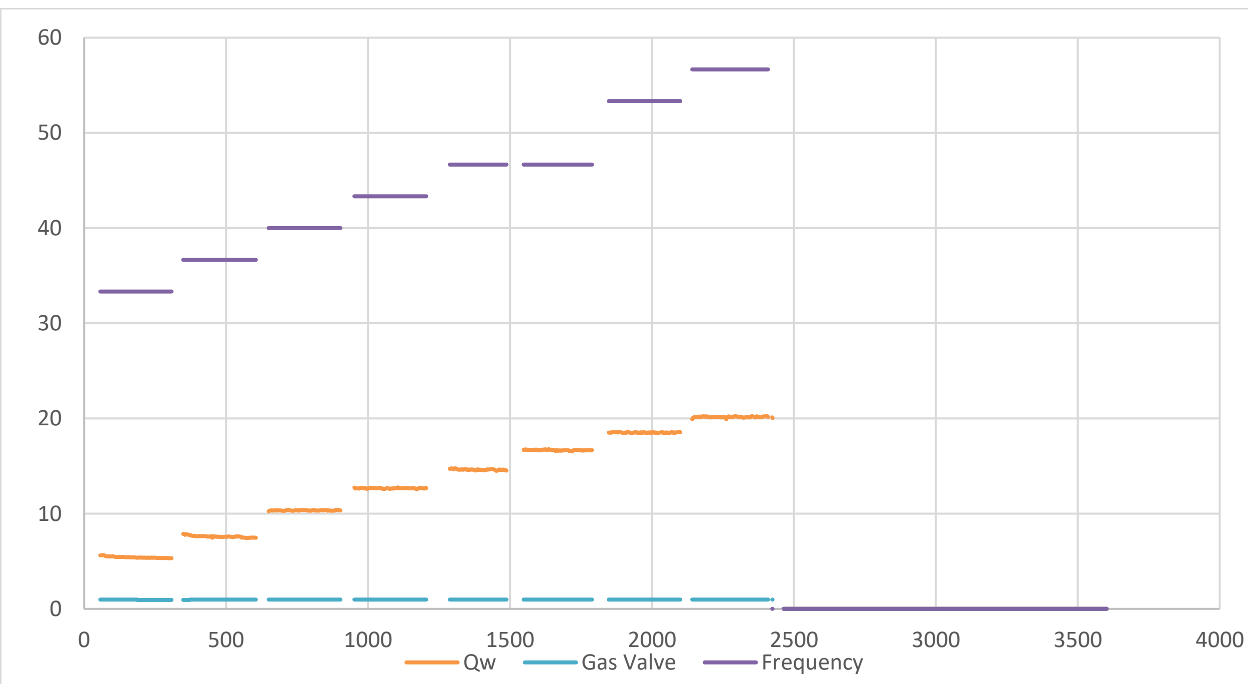

Figure 26: Measured parameters for test 1 at the intake

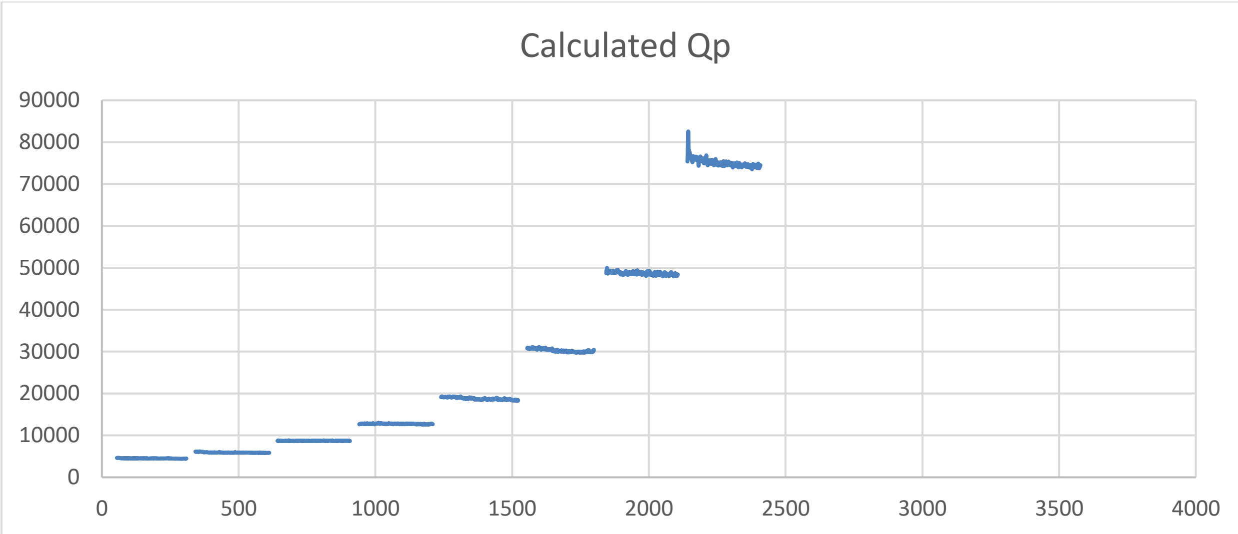

Figure 27: Calculated liquid flowrate for test 1 at the discharge

Analysis: From the above two graphs, it is clear that water flowrate measured at the intake of the pump increases as the frequency increases gradually. No flowrate of oil and gas is present at the intake. The measured liquid rate that is expected at the discharge is increasing significantly high.

Test 2: 18/10/2019

In this test, the testing was done with a fully closed gas and oil valves. No fluid production was observed at the discharge.

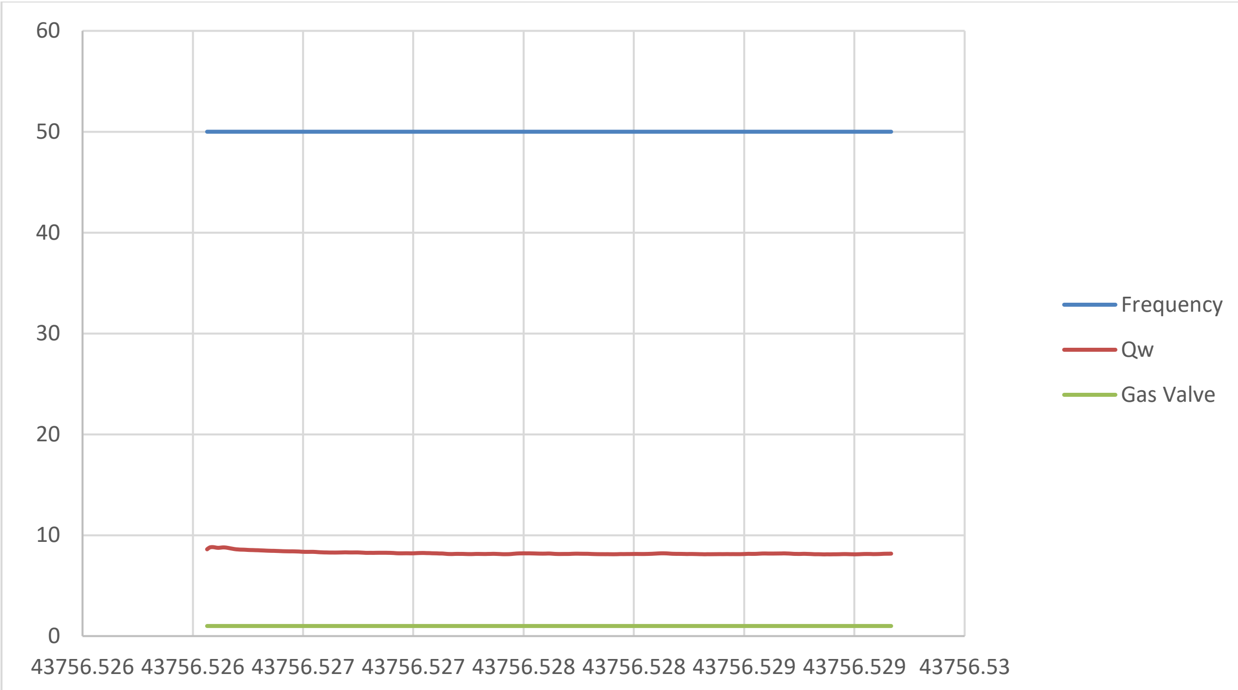

Figure 28: Measured parameters for test 2 at the intake

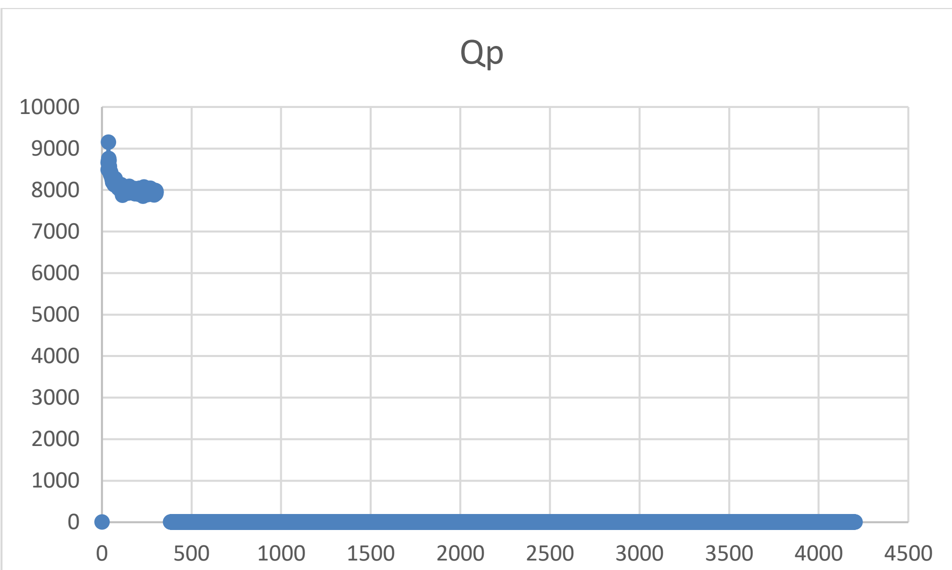

Figure 29: Calculated liquid flowrate for test 2 at the discharge

Analysis: the above two graphs show that no fluid was produced at the discharge. The liquid flowrate calculated is null over the whole testing period and the water flowrate at the intake is also constant for the measurement applied at a constant frequency.

Test 3: 23/10/2019

In this test, the gas valve was re-set at 97% and the water valve is set at 75%. The produced fluid is pure water.

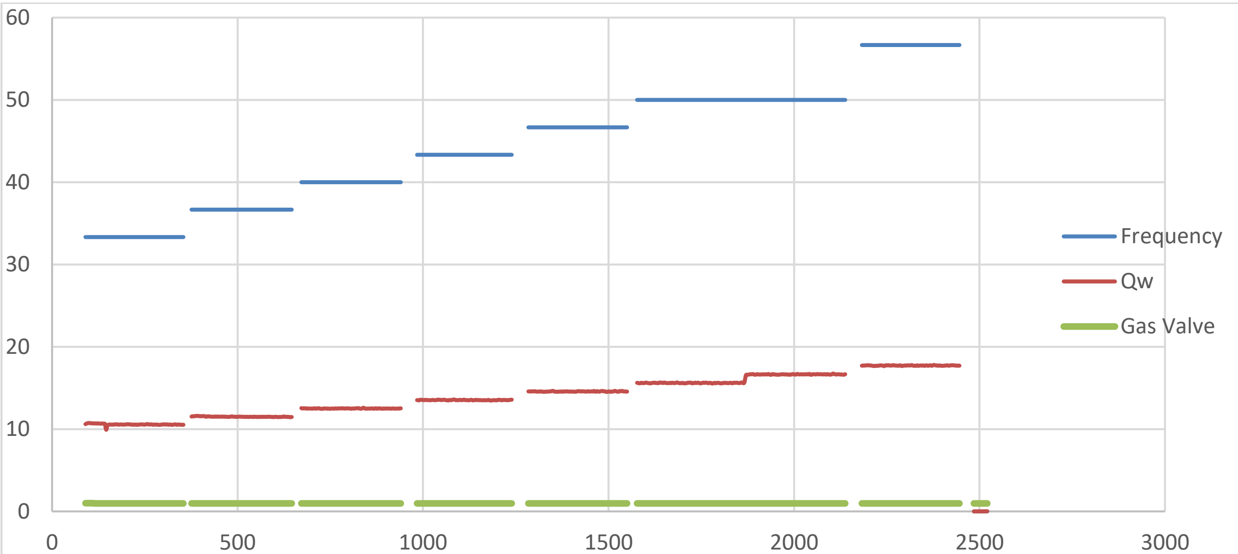

Figure 30: Measured parameters for test 3 at the intake

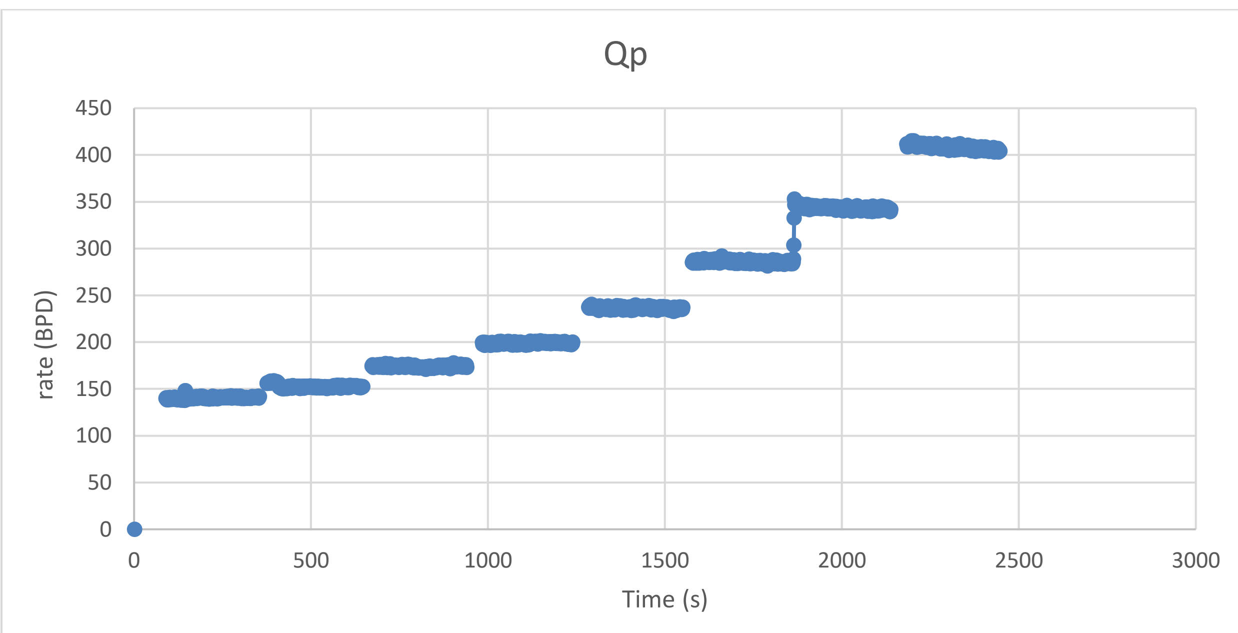

Figure 31: Calculated liquid flowrate for test 3 at the discharge

Analysis: The produced fluid is pure water.The flow rate of the produced fluid at the discharge exhibit lower values compared to test 1.

<u>Test 4: 24/10/2019</u>

During this test, the gas valve was fully closed and the water valve remained slightly open. The produced fluid was pure water.

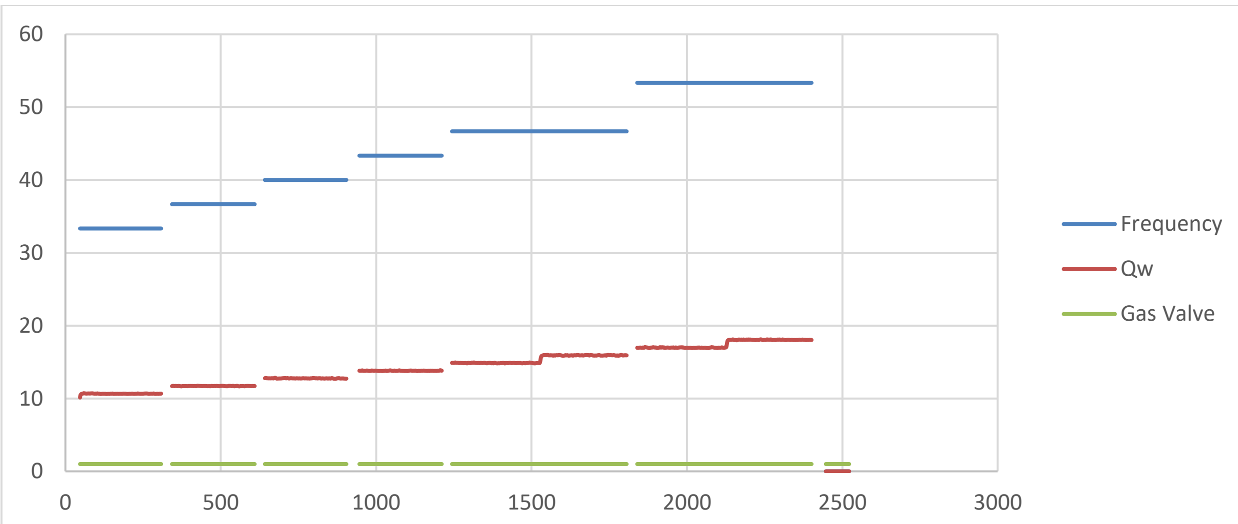

Figure 32: Measured parameters for test 4 at the intake

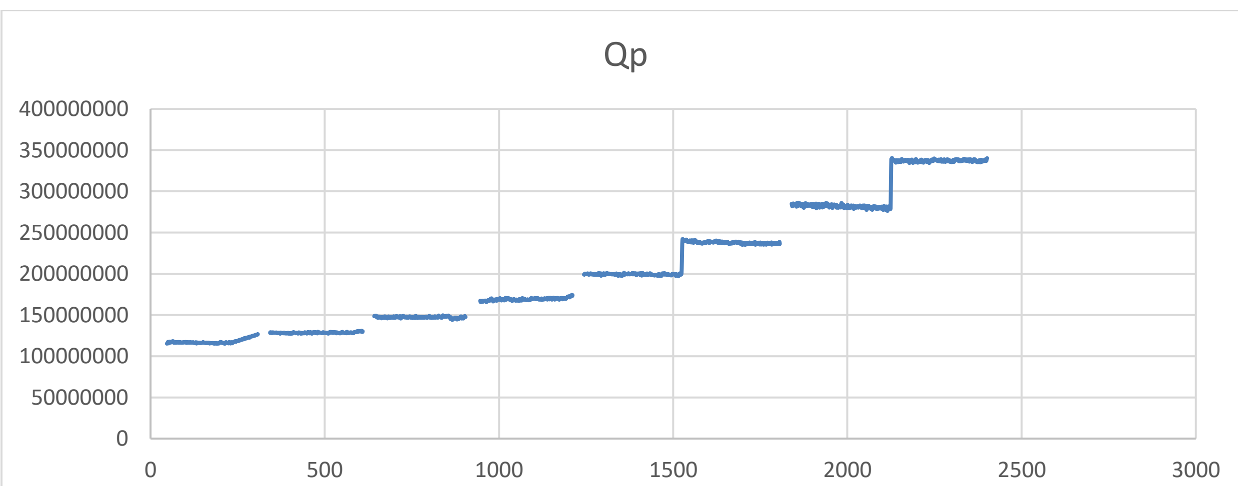

Figure 33: Calculated liquid flowrate for test 4 at the discharge

Analysis: it is clear from the above two picture that when no gas is injected in the pump, the water production is very significant (3.5E+6).

<u>Test 5: 30/10/2019</u>

In this test, the gas valve was reopened. The produced fluid is also water.

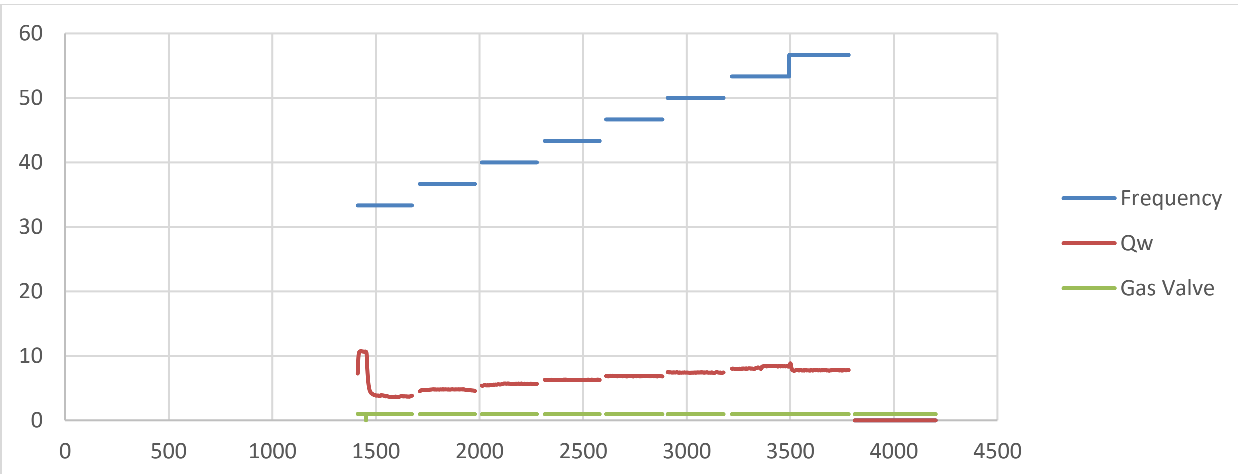

Figure 34: Measured parameters for test 5 at the intake

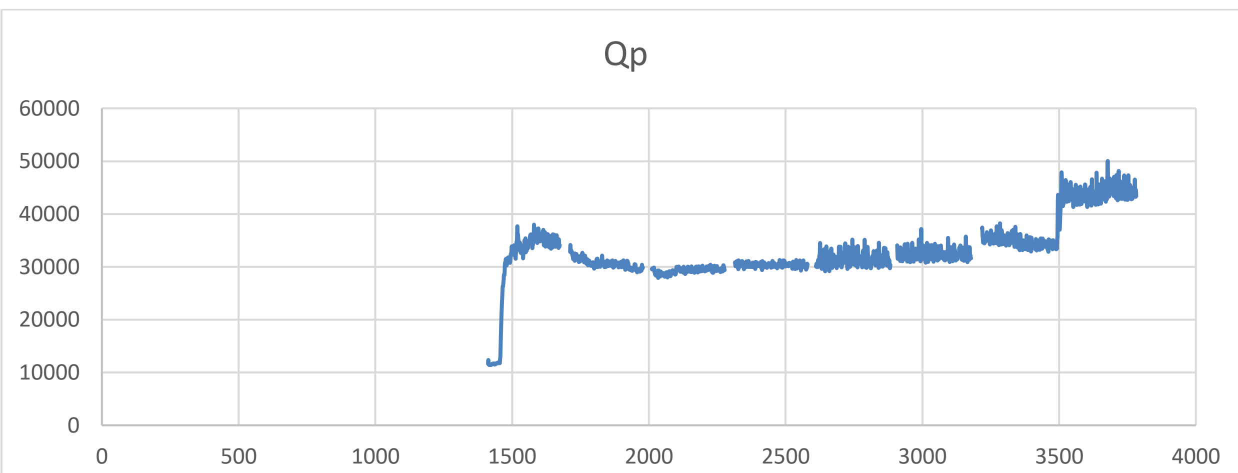

Figure 35: Calculated liquid flowrate for test 5 at the discharge

Analysis: The peak point of each of the above graphs is the point at when the gas valve opens. A decrease in the flowrate values is seen after gas valve opening for both parameters. The water flowrate at the intake increases insignificantly with the frequency and the expected discharge flowrate values are reduced compared to test 4 as gas is re-injected.

<u>Test 6: 21/11/2019</u>

In the following test, oil and gas valves are not fully shut. Each valve is regulated to open and close at a certain point and the illustration of the measured and calculated parameters depends on that. The fluid produced is water.

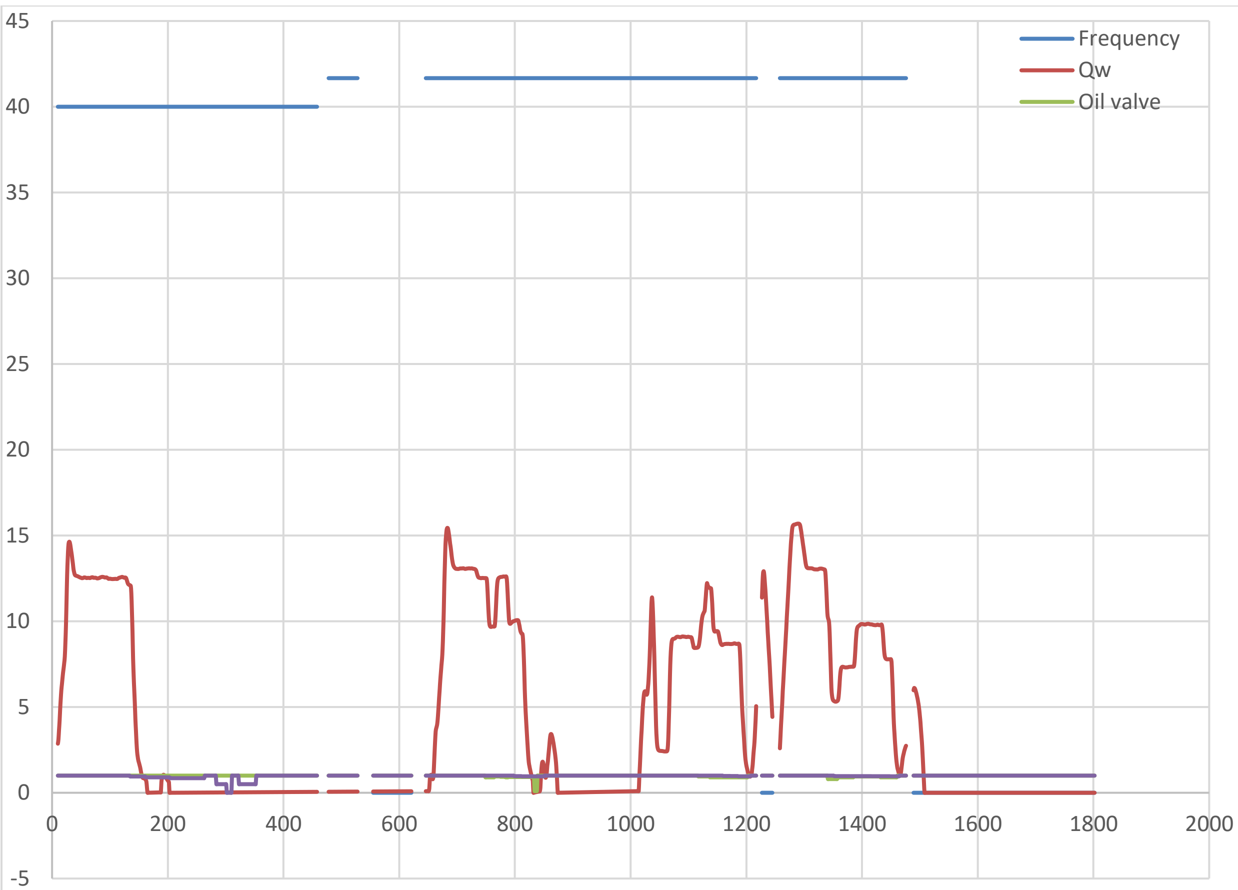

Figure 36: Measured parameters for test 6 at the intake

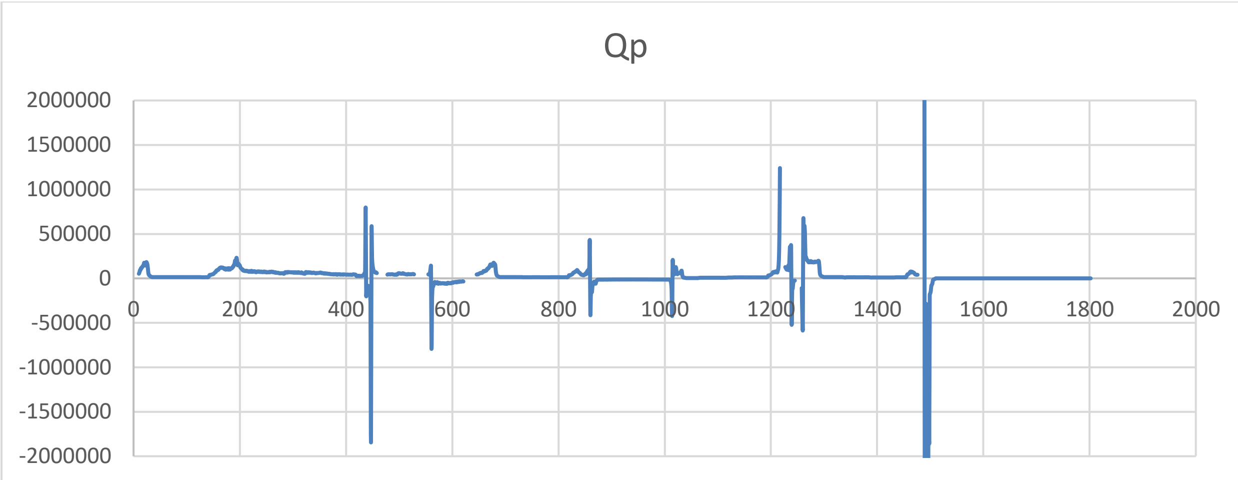

Figure 37: Calculated liquid flowrate for test 6 at the discharge

Analysis: The graphs illustrate a fluctuating behavior. The gas an oil valves are opened and closed numerously during the test. First the gas valve slightly open, and this opening gets larger gradually during the test. The gas valve closes almost fully when the oil valve is opened. The point at which the oil valve opens up, an increase in water flowrate at the intake and discharge is observed.

<u>Test 7: 28/11/2019</u>

In thi test, both gas and oil valves are open to production. The produced fluid is water. Gas and oil rates are both calculated at the intake.

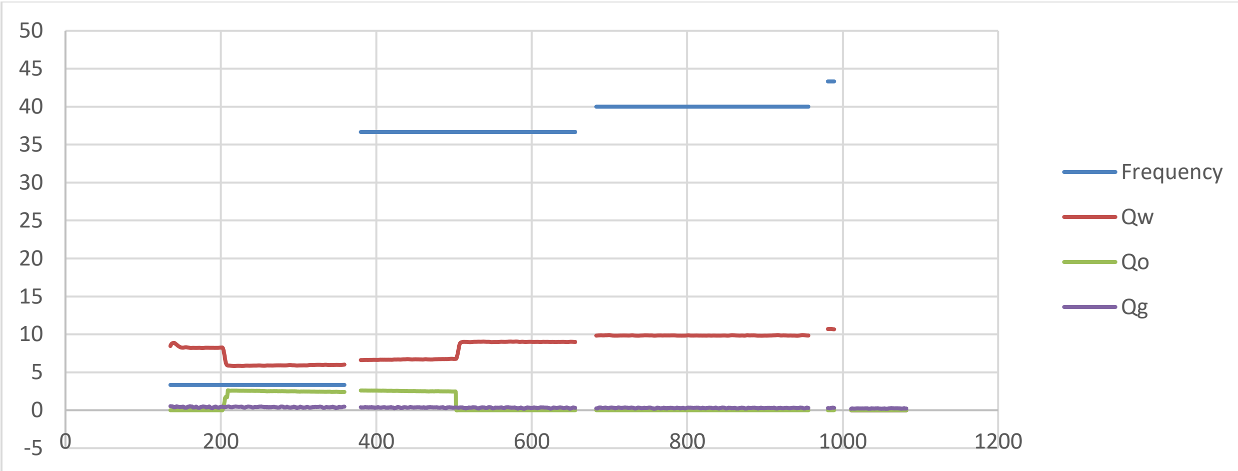

Figure 38: Measured parameters for test 7 at the intake

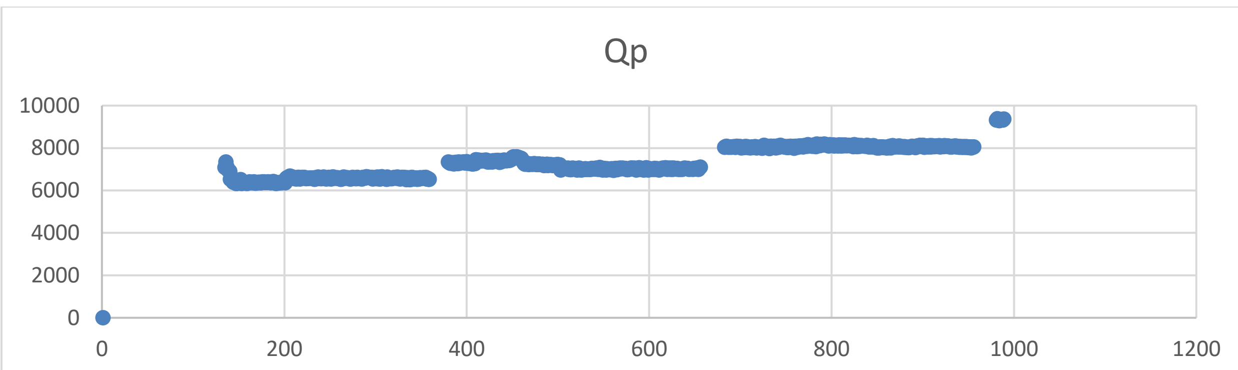

Figure 39: Calculated liquid flowrate for test 7 at the discharge

Analysis: As long as the gas and oil valves are opened, the increase of water rate at the intake and discharge is lowered. The discharged expected flowrate shows slow increasing values. Water production is not significant compared to previous tests.

<u>Test 8: 13/02/2020</u>

In this test, oil valve was fully open and gas valve was at 94%. Both gas and oil rates were measured at the intake and the discharge liquid rate is calculated as oil flowrate since oil is the producing fluid.

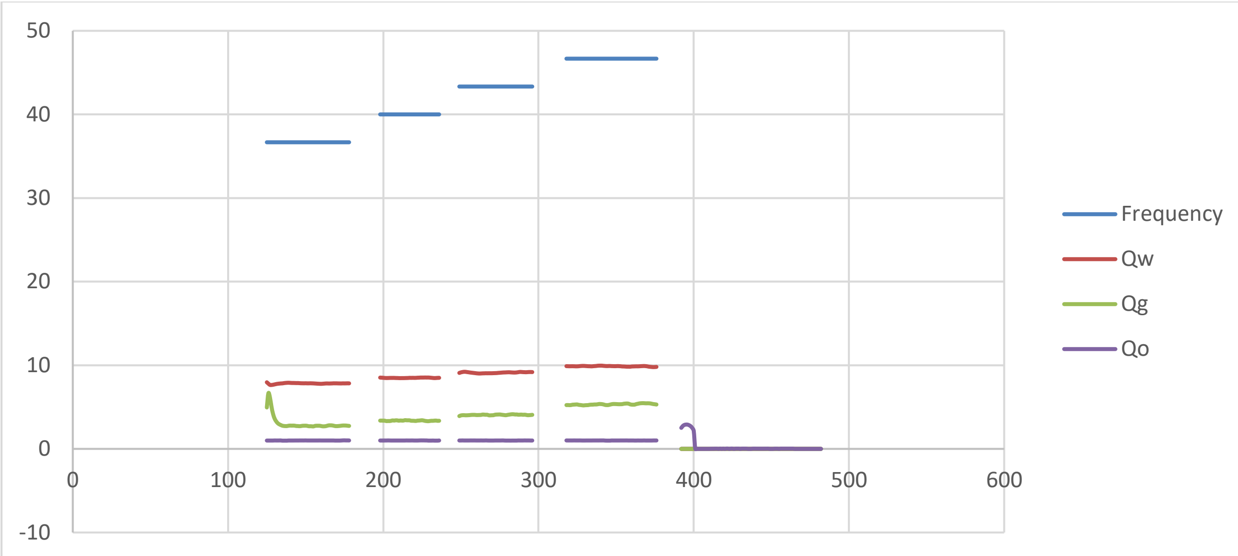

Figure 40: Measured parameters for test 8 at the intake

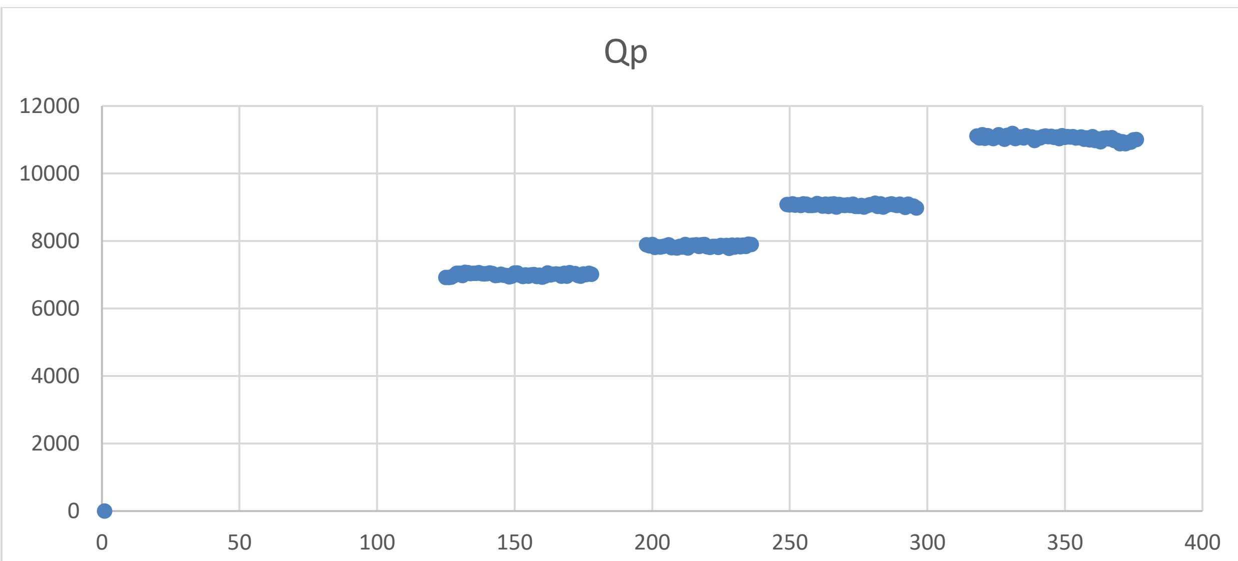

Figure 41: Calculated liquid flowrate for test 8 at the discharge

Analysis: the water flowrate at the intake of the pump is still low and insignificantly increasing with frequency. When the gas valve at the end of the test recloses fully, a sudden decrease in gas and oil rates at the intake is observed and production of oil stops.

5.2. Observations:

The main goal of our mathematical model that was to predict the liquid flowrate at the discharge of the pump is met. The calculated liquid flowrate from the ESP data recorded showed, based on these tests, that the forecast of the produced liquid flowrate depends on ESP parameters and gas injection. I personally found the results quite accurate for a laboratory test facility. The model in my opinion is effective for performing numerous assessments and testing different conditions aiming to reach deductions concerning ESP parameters, ESP monitoring, flowrate measurement accuracy, variation in flowrate with changing ESP parameters, etc.

However, Camilleri L. tested in his five papers the efficiency of the model based on the power equation on an actual producing well. The method in this case needs calibration to improve accuracy. The testing on a well differ from testing in laboratory facility. The method was tested very effective based on Camilleri L. observations and it can be surely used to perform testing in laboratory facilities.

Conclusion

The case study provided a full explanation of the power equation mathematical model investigated in Camilleri et al. five papers. The model was able to calculate and predict the liquid flowrate of a producing ESP laboratory facility without the need of a surface test separator. As many wells produce in the same test separator, it becomes difficult to assign the production rates for each individual well. Hence, this model proved that the possibility of predicting rate based on recorded parameters of an ESP can be very helpful. The importance of having a model that performs real-time flowrate calculations is that the information is delivered to the operators and engineers' desks in real time via the Internet. The fluctuation in production is invisible when performing monthly well tests with traditional flow metering tools. The power equation provides detailed instantaneous liquid flowrate trends even at very low-rate productions. This method was found most efficient in areas exhibiting logistical challenges where the mobilization of surface tests is considered very difficult and costly.

The technique provides an accuracy when testing low flowrate wells requiring long testing periods. It was demonstrated efficient as a surveillance tool of reservoir performance. This surveillance is done by monitoring ESP, determining trends of reservoir pressure, estimate reserves, evaluate inflow performance and identify optimization techniques. The power equation model gives real-time data from downhole gauges, provide full production history and offer calculations with high frequency, repeatability and resolution.

It is necessary to mention that the liquid flowrate calculation from the model described in this case study is considered an enhancement of flow metering surface traditional tools and not a replacement. Verification of the trends calculated must be done using the traditional tools to outcome an accurate well performance evaluation.

To conclude, the virtual flowrate testing model based on the power equation will continue to be effective and valuable in capturing flowrate trends for better well test planning. In future, the goal is to finally be able to manage flowrate trends in limited amount of field data to optimize well operations, work on developing real-time software and IT enhancements for simplifying and automating the model, keep trying to make the model much more affordable, increase accuracy and most importantly to optimize productions.

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