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-THEME-

ARTIFICIAL LIFT: ESP WELL ON BRN FIELD (CASE STUDY OF SFNE 13 OIL WELL)

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Dedication 1

To the one who inserted the taste of life and responsibility

... Thanks, Mom.

To him who has always been the source of inscription and courage

… Thank you, FATHER

To my dear brothers and sisters.

To all my family HAMDI and BOUSNINA. Without forgetting all my friends

Dedication 2

This thesis is dedicated to:

My great parents, who never stop giving of themselves in countless ways,

My dearest wife, who supports me all this journey,

My beloved daughters ***Shahad*** *and* ***Nihal****,*

My friends and all the people who support us in this work.

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Abstract

Artificial lifting of wells is something that will become the most important in the coming years. A large part of fields in the world are going into their late life production, BRN field is a mature field, in which the water's production is increasing and the reservoir's pressure is decreasing. To increase the production and extend the lifetime of the field, the operator company has used the Electrical Submersible Pumps (ESPs) to assist struggling wells.

The first part of the thesis describes the basics of each artificial lift method and its advantage /disadvantage, and the criterions to choose between the different methods, the second part give general detailed about ESP, and the final part is dedicated to the case study of design and the performance evaluation of ESP on oil well suffering from high WC and high salinity using nodal analysis software (Prosper), finally this work is completed by mentioning some problems related to ESP wells on BRN field.

Key words: artificial lift, ESP, Prosper software, water cut, Nodal analysis, optimization, design, pump

Résumé

L'activation artificielle des puits deviendra de plus en plus importante dans les années à venir. Une grande partie des champs du monde entrent dans leur production tardive, le champ BRN est un champ mature, la production d'eau augmente et la pression du réservoir diminue. Pour augmenter la production et prolonger la durée de vie du champ, l'exploitant a utilisé les pompes submersibles électriques (ESP) pour aider les puits en des problèmes.

La première partie de la thèse décrit les bases de chaque méthode de artificiel lift et son avantage / inconvénient, et des critères de choix entre des différentes méthodes, dans la deuxième partie on a détaillé sur ESP, et la dernière partie est consacrée à l'étude de cas et l'évaluation de la performance de l'ESP sur un puits pétrolier souffrant de augmentation WC et de salinité élevées en utilisant un logiciel d'analyse nodale (Prosper), et nous terminons ce travail en mentionnant quelques problèmes des puits en ESP dans le champ BRN.

Mots clés: artificiel lift, ESP, logiciel Prosper, water Cut, analyse Nodale, Optimisation, design, pompe émergé.

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Abbreviations

AC	Alternative current
API	American Petroleum Institute
BEP	Best efficiency point
B_g	Formation Volume Factor of gas
BHP	Bottom-hole pressure
B_O	Formation Volume Factor of oil
BP	Bridge plug
BPD	Barrels / day
BRN	Bir Rabaa Nord
DC	direct current
ESP	Electrical Submersible Pump
ESP_S	Electrical Submersible Pump system
Ft	Foot
GOR	Gas-oil ratio
GSA	Groupement Sonatrach Agip
HSP	Hydraulic Submersible Pump
HZ	Hertz
ID	Inside diameter
MPFM	Melty phase flow meter
OD	Outside diameter
P_{avg}	The average reservoir pressure
PCP	Progressive Cavity Pump
P_{wf}	The bottom hole pressure
RPM	Revolution per minute
P_r	Reservoir pressure
P_e	Drainage area pressure
SG	Specific gravity
P_{ur}	Up narrow pressure
p_{uv}	Up valve pressure
P_{wfs}	Pressure in edge of damaged zone
P_{sep}	Separation pressure
P_{wh}	Well head pressure
P_{dv}	Down valve pressure
PETX	Petroleum Experts
PIP	Pump Intake Pressure
PID	Pump Discharge Pressure
PLT	Production logging tool
PVT	Pressure – volume - temperature
Q_O	oil flow rate
q_{max}	Max flow rate
Q	Flow rate
ROR	Recommended operating range
ROR	Recommended operating range
Sg	Specific gravity
TDH	Total Dynamic Head
VSD	Variable Speed Drive
WC	Water cut
WHP	Well head pressure

General Introduction

GENERAL INTRODUCTION

All reservoirs contain energy in the form of pressure, in the compressed fluid itself and in the rock, making it easy to recover. However, in other reservoirs, the rocks do not part as easily with the oil and gas, and require special techniques to move fluids from the pore spaces in reservoir rock to the surface.

The driving force in a reservoir is either by water or gas. A water drive reservoir occurs when there is a big underlying aquifer where the water is able to flow into the oil layer.

Once production from the oil layer begins it will create a pressure drop. The aquifer then responds by expanding up into the oil's layer to replace the empty place. A gas drive reservoir derives its energy from gas expansion of a gas cap or from breaking out from the pressurized oil. Early in a well's production life the reservoir, the pressure will be sufficient to push the hydrocarbons up to the surface. When the pressure differential becomes insufficient for the oil to flow naturally, some methods of lifting the oil to surface must be implemented. One can either use something called pressure maintenance or artificial lift. Pressure maintenance is about injecting water or gas into the reservoir to maintain the pressure on an acceptable level.

Artificial lift systems distinguish themselves from pressure maintenance by adding energy to the produced fluids in the well; the energy is not transferred to the reservoir.

The purpose of any artificial lift method is to add energy to the produced fluids, either to improve or to enable production. Some wells need artificial lift to increase production rate, and others need artificial lift to be able to start producing. There are several different forms of artificial lift that can be used for different operating condition.

In our memory we divided the work on three chapters

1st chapter was dedicated for introducing every method of artificial lift and highlight its advantages and limitations, with methodology of selection between different types of AL.

2nd chapter is dedicated to the ESP with very detailed information about its parts.

3rd chapter is a real case study of design and installation of ESP system on oil well (SFNE 13) surfing from high WC with the evaluation of the well performance after the deployment this system.

Chapter I. Artificial lift

CHAPTER I: ARTIFICIAL LIFT

I.1 Definitions

Artificial lift is a process used on oil wells to increase pressure within the reservoir and encourage oil to reach the surface. When the natural drive energy of reservoir is not strong enough to push the oil to the surface, artificial lift is employed to recover more production.

Artificial lift refers to the use of artificial means to increase the flow of liquids, such as crude oil or water, from a production well. Generally this is achieved by the use of a mechanical device inside the well (known as **pump** or velocity string) or by decreasing the weight of the hydrostatic column by injecting gas into the liquid some distance down the well.

Artificial lift is needed in wells when there is insufficient pressure in the reservoir to lift the produced fluids to the surface, but often used in naturally flowing wells (which do not technically need it) to increase the flow rate above what would flow naturally. The produced fluid can be oil, water or a mix of oil and water, typically mixed with some amount of gas.

Artificial lift is a means of overcoming bottom-hole pressure so that a well can produce at some desired rate, either by injecting gas into the producing fluid column to reduce its hydrostatic pressure, or using a downhole pump to provide additional lift pressure down hole.

We tend to associate artificial lift with mature, depleted fields, where $\mathbf{P_R}$ has declined such that the reservoir can no longer produce under its natural energy. But these methods are also used in younger fields to increase production rates and improve project economics.

I.2 Purpose of artificial lift

The purpose of artificial lift is to maintain a reduced producing bottom-hole pressure so the formation can give up the desired reservoir fluids. A well may be capable performing this task under its own power. In its latter stage of flowing life, a well is capable producing only portion of the desired fluid. During this stage of a well’s flowing life the particularly after the well dies, a suitable means of artificial lift must be installed so the required flowing bottom hole pressure can be maintained. [1]

Maintaining the require flowing bottom hole pressure is the basis for the design of any artificial lift installation. If a predetermined drawdown in pressure can be maintained, the well will produce the desired fluid this is true regardless of the type of lift installed

Many types of artificial lift methods are available ; sucker rod pumps, hydraulic oil well pumps , electrical submergible centrifugal pumps , rotating rod pumps, plunger lift , gas lift , and others . [1]

I.3 Artificial lift methods

The basic information (concept, application, positive and negative features) concerning the following Artificial Systems will be provided:

- ✓ Gas Lift.
- ✓ Electrical Submersible Pump (ESP).
- ✓ Hydraulic Submersible Pump (HSP).
- ✓ Jet Pump.
- ✓ Progressive Cavity Pump (PCP).
- ✓ Beam or Sucker Rod Pump.

I.3.1 *Gas Lift*

Gas lift consist of injecting high pressure gas from the surface to a predetermined tubing string depth to decrease fluid density in wellbore therefore reducing the hydrostatic load on formations which will allow reservoir energy to cause inflow and commercial hydrocarbon volumes can be boosted or displaced to the Surface. The gas injected through the operating valve in the tubing string enables the well to resume or increase production by:

● reducing the average fluid density above the injection point.

● Some of the injected gas dissolving into the produced fluids (under saturated) and the remaining in form of bubbles will expand as the fluid rise up the tubing string. [2]

***Advantages*:**

● Preferred method for wells with:

– High gas oil ratio.

– High productivity index.

– Relatively high bottom hole pressure.

● Suitable for medium rate.

● Suitable for water drive reservoirs with high bottom-hole pressure.

● Provides full bore tubing string access.

● Low operational and maintenance cost.

● Flexibility: can handle rates from 10 to 20.000 bpd.

● Can handle (tolerate) produced solids

● Low surface profile, important for offshore / urban locations.[3]

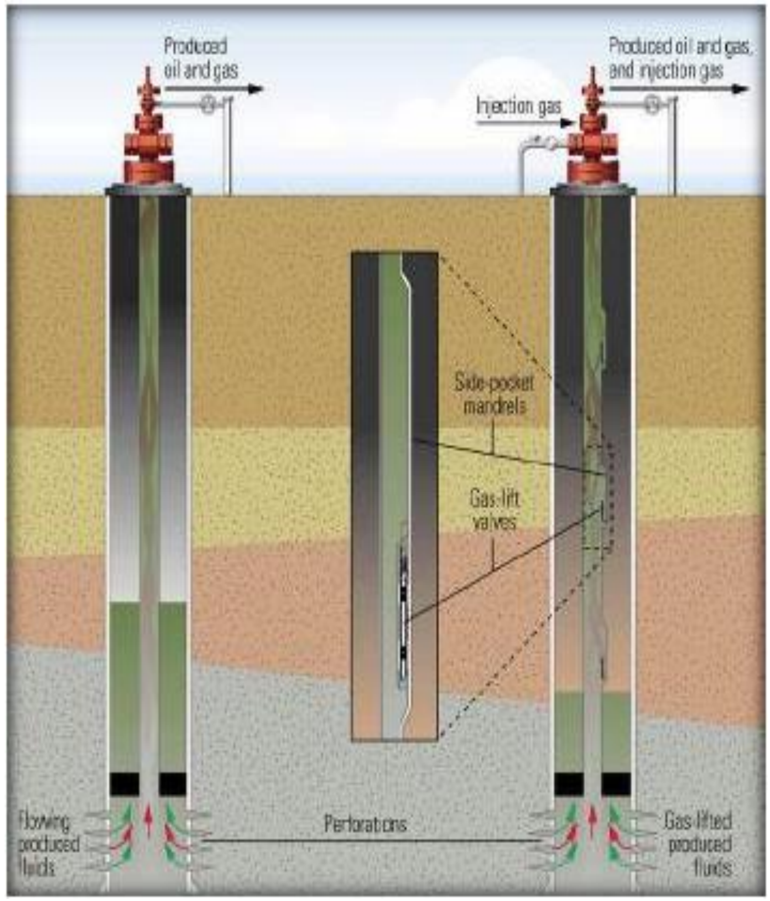


Figure I.1 Gas lift completion (3)

***Disadvantages*:**

● Gas has to be available.

● possible high installation cost:

- ❖ Compressor installation.
- ❖ Modifications to existing platforms.

● Gas lifting of viscous crude (<15 API) is difficult and less efficient.

● Difficult restart after shut down.

● Wax precipitation problem may increase due to cooling effect from gas injection and subsequent expansion.

● Hydrate blocking surface gas injection lines can occur if gas inadequately dried.

● Limited by reservoir pressure and bottom hole flowing pressure.[3]

I.3.2 *Electrical Submersible Pump*

The Electric Submersible Pump (**ESP**) is a multistage centrifugal pump driven by a downhole electric motor.

The pump unit consists of a stacked series of rotating centrifugal impellers running on a central drive shaft inside a stack of stationary diffusers, it is essentially a series of small turbines.

The flow rate through the pump will thus vary depending on the back pressure held on the System.

The necessary rate and pressure to lift liquids to surface are determined by the type and **number of pump stages**.

The ESP is run in hole **suspended to the production tubing**. Therefore, if the down hole unit fail, the tubing and pump should be pulled out together for repairs.[4]

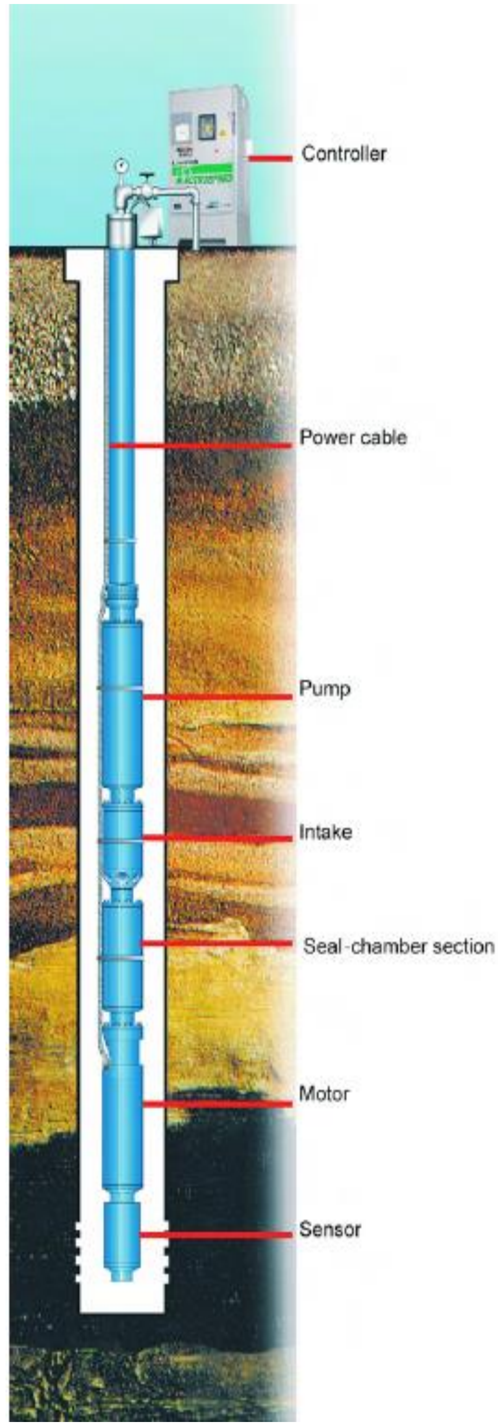


***Figure I.2 ESP well* (3)**

***Advantages*:**

● Preferred method for wells with:

- ❖ Low gas oil ratio.
- ❖ High productivity index.

●High water cut is not a restriction.

● can lift extremely high volume.

● Flexibility: can handle rates from50 to 60.000 bpd.

● Controllable production rate.

● Comprehensive down-hole measurement.

● Real time pump and well performance monitoring.

● Can pump against high flow-tubing head pressure.

● Quick restart after shut down.

● Long run pump life possible.[3]

***Disadvantages*:**

● not applicable in case of:

- ❖ High GOR.
- ❖ Sand production.

● Tubing has to be pulled to replace the pump.

● High cost for repairs, especially offshore.

● High voltage (1000 V) electrical powers required.

● Susceptible to damage during completion.

● No suitable for low volume wells: <150BPD.

● Power cable requires penetration of head and packer integrity.

● Viscous crude reduce pump efficiency

● High temperature can degrade the electrical motor. [3]

I.3.3 *Hydraulic Submersible Pump*

Hydraulic pumps use a high pressure power fluid pumped from the surface which:

●Drives a downhole, positive displacement pumps.

● Powers a ***centrifugal or turbine pump.***

● Creates a reduced pressure by passage through a ***venturi or nozzle*** where pressure energy is converted into velocity.
this high velocity/low pressure flow of the power fluid commingles with the production flow in the throat of the pump. [4]

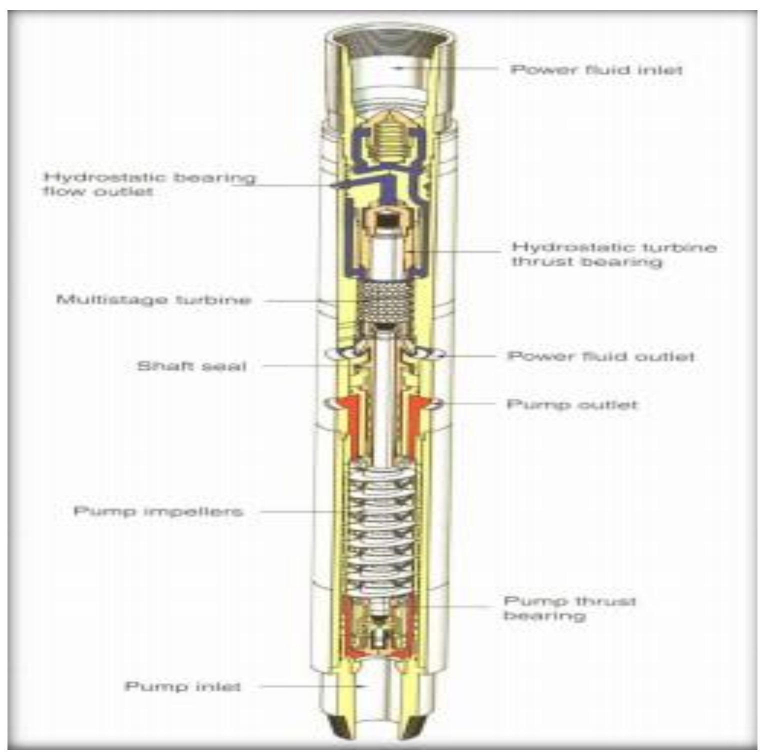


***Figure I.3 Hydraulic Submersible Pump* (4)**

A ***diffuser*** reduces the velocity, increasing the fluid pressure and allowing the combined fluid to flow to surface.

- ➢ The power fluid consists of oil or production water.
- ➢ The power fluid is supplied to the down-hole equipment via a separate ***injection tubing.***
- ➢ The majority of installations commingle the exhaust fluid with the production fluid through the casing-tubing annulus.[4]

***Advantages*:**

● Range of application opportunities:

- ❖ Small diameter wells not suited to other Artificial lift methods.
- ❖ Tough retrofit completion and tough liquid applications.
- ❖ As good alternative to the ESP.

● The pump operate at higher speed than an ESP (around three-four times higher revolution/min) therefore they require few stages and are smaller.

● No electrical connections or down-hole electronics.

● Flexibility: can handle rates from50 to 20.000 bpd.

● Simple to operate: speed control by the variation of supplied power fluid.

● the power source can be remote from the wellhead giving a low wellhead profile attractive for offshore locations.

● the power fluid can be commingled or returned in a separate conduit or disposed of down-hole. [3]

***Disadvantages*:**

● Pumps with moving parts have a short run life when supplied with poor quality power fluid. Solid-free power fluid is mandatory.

● Commingle power-produced fluid imply:

- ❖ power-produced fluids compatibility.
- ❖ power-produced fluids separation.

● High GOR represent gas handling problems.

● viscous crude reduce pump efficiency. [3]

I.3.4 *Jet Pump*

Jet pumps are the only form of artificial lift that **require no down-hole moving parts.**
Jet pump is an ejector-type dynamic-displacement pump operated by a stream of high-pressure power fluid that converges into a jet in the nozzle of the pump.

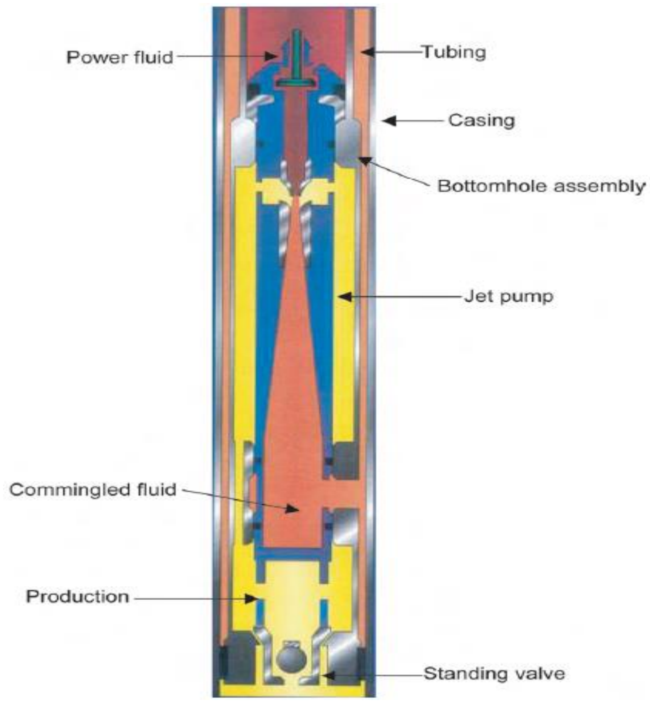


Figure I.4 jet pump (4)

Downstream from the nozzle, the high-velocity, low-pressure jet is mixed with well's fluid.

The stream of the mixture is then expanded in a **diffuser**, and as the flow velocity drops, pressure is built up. They find wide application, generally **in low to moderate-rate wells.** [4]

***Advantages*:**

- No down-hole moving parts.
- Compact and reliable.
- Easily installed and retrieved by wire line.
- No electrical connections or down-hole electronics.
- Simple to operate: Ideal for remote areas.
- Power fluid does not to be so clean as for hydraulic piston pumping.[3]

***Disadvantages*:**

- less efficient than other pump systems.
- Require large volume of power fluid.
- Power fluid and reservoir fluids mast mix, so a key issues is the selection of an appropriate power fluid.

This disadvantage can be turned into an advantage in heavy oil application.

- requires at least 20% submergence to approach the best lift efficiency.
- Very sensitive to any change in backpressure. [3]

I.3.5 *Progressive Cavity Pump*

Progressive cavity pumps (PCPs) are a common form of artificial lift for low to moderate rate wells**,** especially onshore and for heavy (and solid laden) fluids.

PCPs are positive displacement pumps, unlike Jet pumps, ESPs and HSPs.

Their operation involves the rotation of a metal spiral rotor inside either a metal or an elastomeric spiral stator.

Rotation causes the displacement of a constant volume cavity formed by the rotor and the stator.

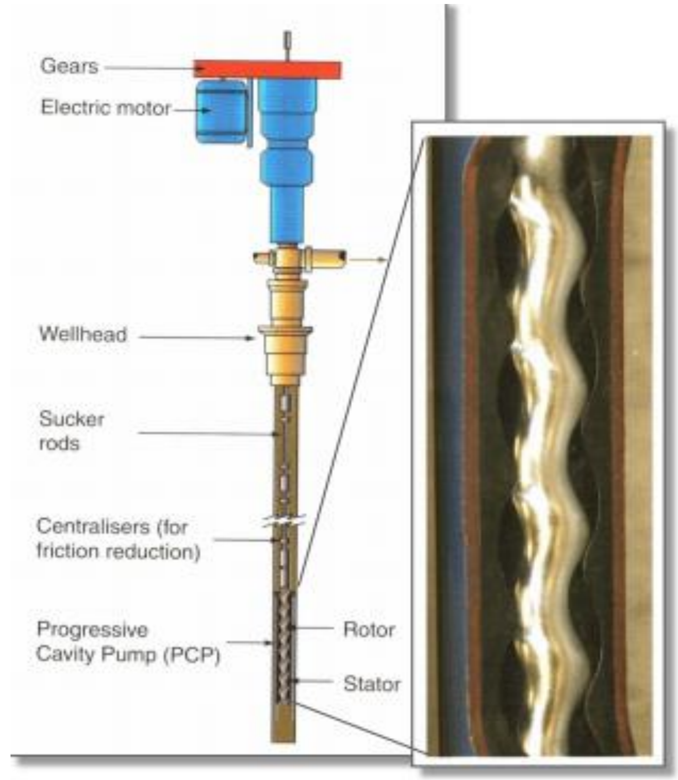


Figure I.5 PCP components (4)

- The area and the axial speed of this cavity determine the "no-slip" production rate.
- The pump in normally driven by an electric motor[4]

***Advantages*:**

● Simple design.

● Quick pump unit repaired by replacing rotor and stator as a complete unit.

● High volumetric efficiency, in absence of gas.

● High energy efficiency: above 80%.

● Emulsion not formed due to low shear pumping action – ESP and HSP pumps promote emulsion formation due to high pump speeds.

● Capable of pumping viscous crude oil**:**

- Diluents mixed as required with crude oil if extreme viscosities to be pumped.
- Water-like behavior observed at high water cuts when oil becomes the internal phase.

● Performances:

- Oil rate: up to 6000 BOPD.

❖ Pressure: up to 3000 psi.

● Long live with no abrasive fluid.
● Compact and reliable.
● Simple to operate: Ideal for remote areas. [3]

***Disadvantages*:**

● High starting Torque.
● Short live with abrasive fluid.
● The presence of the Elastomeric seal is the Achilles hell of PCP pump. [3]

I.3.6 *Sucker Rod Pump*

The Sucker Rod Pump is **the oldest and most common artificial lift method,** simple in design and still widely used over the world. It is **very economical in low production wells** in shallow to middle depth oil fields.

The system uses a **vertical positive-displacement pump** consisting of a **barrel** with a check valve at its bottom (**Standing Valve**) and a **Plunger** fitted with another check valve (**Traveling Valve**). [2]

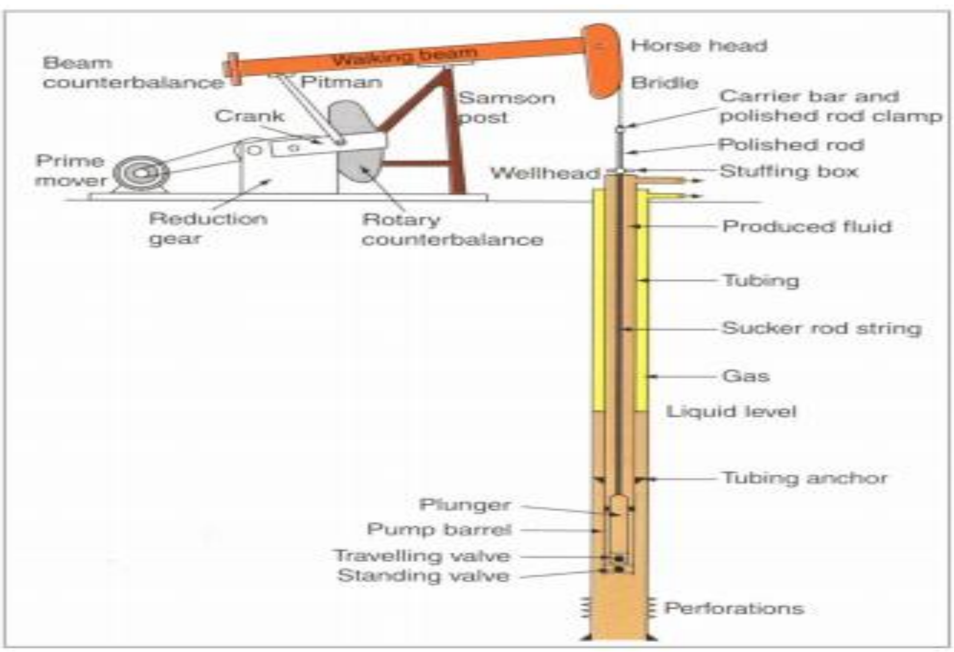


***Figure I.6 Sucker Rod pump* (4)**

The downhole Plunger is mechanically connected to a surface walking beam by Sucker rods string.

The pump is rocked up and down by the movement of the walking beam driven by an electric or reciprocating motor.

● During the plunger's upstroke, the standing valve opens, the traveling valve closes and the barrel fills with fluid.

● During the down stroke, the traveling valve opens, the standing valve closes and the fluid in the barrel is displaced in the tubing.

● The pumping capacity of the Beam Pump is governed by several factors including pumping speed, stroke length, plunger type and size and pump efficiency. [2]

***Advantages*:**

● most wide spread artificial lift system, relatively simple, cheap and best known by field personnel.

● Low rate: less than 100 bpd.

● Low intake pressure.

● Rod pumps are mechanically simple, to operate and easy to repair maintain and replace.

● readily accommodates volume changes; flexible operation.

● viscous oil can be pumped.

● rather low operating expenses. [3]

***Disadvantages*:**

● Sensitive to gas.

● Maximum capacity decreasing rapidly with depth.

● Sensitive to solids (wax/scale/sand).

● Sucker rods susceptible to corrosion.

● Equipment too heavy for offshore.

● No suitable for highly deviated wells. [3]

I.4 Artificial lift system selection

In artificial lift design the engineer is faced with matching facility constraints, artificial lift capabilities and the well productivity so that an efficient lift installation results. Energy efficiency will partially determine the cost of operation, but this is only one of many factors to be considered.

In the typical artificial lift problem, the type of lift has already been determined and the engineer has the problem of applying that system to the particular well. The more basic question, however, is how to determine, what is the proper type of artificial lift to apply in a given field?

Selection of the most economical artificial lift method is necessary for the operator to realize the maximum potential from developing any oil or gas field. Historically the methods used to select the method of lift for a particular field have varied broadly across the industry, including**:**

- Determining what methods will lift at the desired rates and from the required depths.
- Evaluating lists of advantages and disadvantages.
- Use of "expert" software to both eliminate and select AL systems.
- Evaluation of initial costs, operating costs, production capabilities, etc. Using economics as a tool of selection. [5]

The operator should consider all of these methods when selecting a method of artificial lift, especially for a large, long-term project.

The main factors governing selection of artificial lift methods are:

1. Production rate to be achieved.
2. Down-hole flowing pressure.
3. Gas-liquid ratio GOR.
4. PVT producing fluid characteristics.[4]

The other factors to be considered are:

I. **Operating conditions:**

- ✓ Casing size limitation
- ✓ Well depth
- ✓ Intake capabilities (minimum bottom hole flowing pressure)
- ✓ Flexibility of the artificial lift system
- ✓ Surveillance
- ✓ Testing, and time cycle or pump off controllers[4]

II. **Well conditions:**

- ✓ Corrosion/ scale-handling ability
- ✓ Solids/sand handling ability
- ✓ Temperature limitation
- ✓ High-viscosity fluid handling
- ✓ High and low –volume lift capabilities.

III. **Situation** (new field discovery , new well , existing well ,existing of gas)**:**

Many choices may be available for a ***new field discovery***, for which constraints can be minimized by the production facilities and well design.

- ➢ A ***new well in an existing field*** is constrained by the ***existing infrastructure:*** choices become limited.
- ➢ An ***existing well*** has many ***fixed constraints*** (completion, well integrity, location accessibility, distance between wells, etc.) that minimize lift selection possibilities. [4]

The original field development plan should address all known constraints and consider **future changes** (depletion, GOR, water cut) to the lift method.

As a result of the above considerations, the type of artificial lift system should be selected:

1. Positive displacement pumps (PCP, Sucker Rod, Reciprocating Hydraulic pump).

2. Dynamic displacement pumps (ESP, HSP, Jet pump).

3. Gas lift. [4]

Based on reservoir production performance analysis, two different approaches should be investigated:

I. **Long term**

This frequently leads to the installation of oversized equipment in the anticipation of ultimately producing large quantities of water. As a result, the equipment may have operated at poor efficiency due to under-loading over a significant portion of its total life. [4]

II. **Short term**

Essentially, to design for what the wells is producing today and not worry about tomorrow. This can lead to many changes in the type of lift equipment installed during the well's production life. Low cost operations may result in the short term, but large sum of money will have to be spent later on to change the artificial lift equipment and /or the completion. [4]

I.5 CONCLUSION

According to Society of petroleum Engineers **SPE (on 2002)** there are approximately **2 million** oil wells in operation worldwide. More than 1 million wells use some type of artificial lift. That's mean **50%** of worldwide oil production coming from artificially lifted wells. More than 750,000 of the lifted wells use sucker-rod. These statistics indicate the dominance of rod pumping for onshore operations. For offshore and higher-rate wells around the world, the use of ESPs and gas lift is much higher.

The petroleum industry extensively uses ESPs as an artificial lift method for producing oil wells. The application of ESPs to oil production began more than 8 decades ago and has grown greatly, judging from the industry's annual ESP expenditures.

In 2009, **Spears & Associates** estimated that ESP expenditures were 58% of the total artificial lift market of $5.8 billion. In other words, the industry spends more money annually on ESPs than for all other forms of artificial lift combined.

The next chapter is dedicated to ESP since that's the most used method for high rate wells, and high water cut wells and our case study will be about the design and optimization of an ESP well.

Chapter II. Electrical Submersible Pump

CHAPTER II: ELECTRICAL SUBMERSIBLE PUMP

II.1 Introduction

What Is an **Electrical Submersible Pump**? The electrical submersible pump, typically called an ESP, is a multistage centrifugal pump it's efficient and reliable artificial-lift method for lifting moderate to high volumes of fluids from wellbores. These volumes range from a low of 150 B/D to as much as 150,000 B/D (24 to 24,600 m^3/day).

Throughout their history, ESP systems have been used to pump a variety of fluids. Normally, the production fluids are crude oil and brine, but they may be called on to handle liquid petroleum products; disposal or injection fluids; and fluids containing free gas, some solids or contaminates, and CO2 and H2S gases or treatment chemicals. ESP systems are also environmentally esthetic because only the surface power control equipment and power cable run from the controller to the wellhead are visible. The controller can be provided in a weatherproof.

II.2 History of ESP

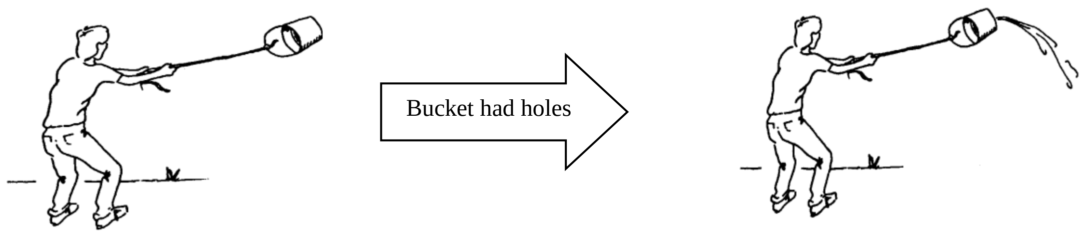
In 1911, 18-year-old **Armais Arutunoff** organized the Russian Electrical Dynamo of Arutunoff Co. in Russia, and invented the first electric motor that would operate in water. During World War I, Arutunoff combined his motor with a drill. It had limited use to drill horizontal holes between trenches so that explosives could be pushed through. In 1916, he redesigned a centrifugal pump to be coupled to his motor for dewatering mines and ships. In 1919, he immigrated to Berlin and changed the name of his company to **REDA**. In 1923, he immigrated to the United States and began looking for backers for his equipment. In 1926, at the American Petroleum Institute (API) conference in Los Angeles, two parties joined together to start the ESP industry. Just before this conference, Arutunoff had joined forces with Samual VanWert, a sucker-rod salesman who saw the potential of the new device. Together, they initiated a prototype test in a Baldwin Hills oil well. This was the birth of REDA Pump Co. In 1969, REDA merged with TRW Inc., and in 1987, it was sold to Camco Intl., which merged with Schlumberger in 1998. [6]

In 1979, Centrilift Inc. was established as second company manufacturing ESP, Just after the relocation in 1980, Centrilift was sold to Hughes Tool Co. Then, in 1987, Hughes Tool and

Baker Intl. merged to become Baker Hughes Inc. and last year 2017 Baker merged with General Electric. [2]

II.3 **Principle of Centrifugal Pumps**

When you spin a bucket full of water around your head. The water stayed in the bucket as long as you kept the bucket turning at speed: the same force that kept the water in the bucket is at work in centrifugal pumps.



The force that causes the water to leave the impeller (or bucket) is centrifugal force, which is where centrifugal pumps get their name. [2]

II.4 **The Components of ESP system**

II.4.1 ***Surface components***

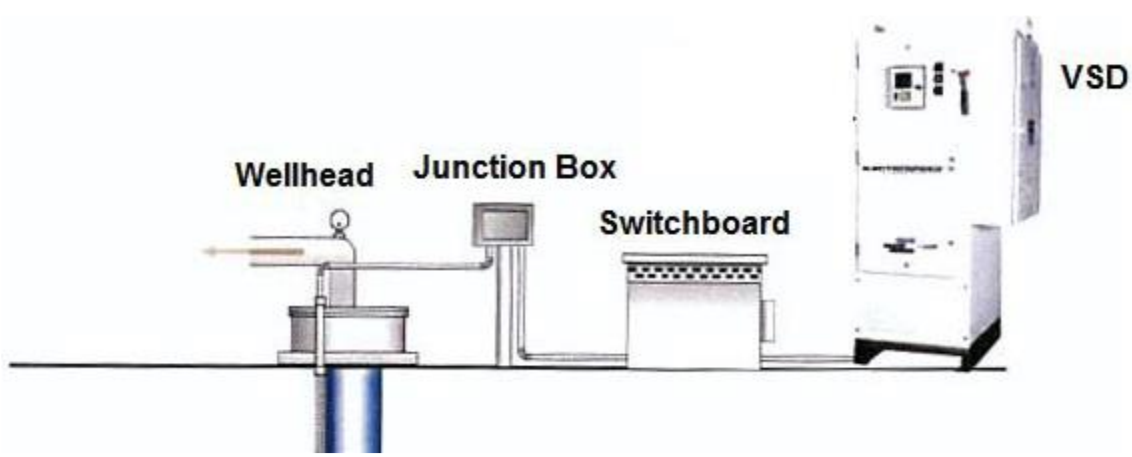


Figure II.1 Surface instalation for ESP well (2)

II.4.1.1 ***Wellhead***

The wellhead is designed to support the weight of the subsurface equipment and to maintain the surface annular control of the well. It is selected on the basis of casing and tubing size, maximum recommended load, surface pressure, and the power cable pass through requirements. The Wellhead is the equipment that is installed at the surface of the wellbore its purpose is to:

- Suspend the tubing string.
- Provide a pressure tight pack-off around the tubing and power cable.
- Carry the weight of the down-hole equipment and maintain annular control. They need to seal off the tubing and the electric. [7]

Figure II.2 Junction box (7)

II.4.1.2 ***Junction box***

The electric cable from the well is joined with the cable from the switchboard inside the junction box, the junction box performs the following functions:

- A junction box connects the power cable from the switchboard to the well power cable.
- Allows for any gas to vent that may have migrated through to the power cable. This prevents accumulation of gas in the switchboard that can result in an explosive and unsafe operating condition. *A* junction box is required on all ESP installations.
- Provides easy accessible test point for electrically checking down-hole equipment. [7]

Figure II.3 Switch board (7)

II.4.1.3 ***Switch board (motor controller)***

The switchboard is basically a motor control device. Voltage capability ranges from 600 to 4.900 Volt on standard switchboards.

The switchboards range in complexity from a simple motor starter/disconnect switch to an extremely sophisticated monitoring/control device. The purpose of motor controller is to protect the down-hole unit by sensing abnormal power service and shutting down the power supply. The monitoring function applies to both overload and under-load conditions. It can be programmed to automatically restart the down-hole motor following a user-selected time delay if the fault condition is caused by an under-load. Overload condition shut-down must be restarted manually. This should be done only after the fault condition has been identified and corrected. The controller also provides the capability to monitor the Production system with the use of a recording instrument. [7]

Figure II.4 Transformer (6)

II.4.1.4 ***Transformer***

Transformers generally are required because primary line voltage does not meet the down-hole motor voltage requirements. Normally, three individual transformers are connected together, in various configurations

Transformer Oil-immersed self-cooled (OISC) transformers are used in land-based applications.

Dry type transformers are used in offshore applications .A single-phase transformer generally appears similar to the figure shown. [6]

II.4.1.5 ***Variable Speed Drive (VSD)***

VSD makes it possible to vary ESP performance by controlling the speed of the motor. If this is achieved it can have the following main benefits:

- better control of motor temperature.
- improve gas handling.
- adjust to changing well conditions .

Normally in oil fields power supply voltage is quite high and the required surface voltages should be individually adjusted on each well. If a VSD unit is used, the VSD provides the required frequency Step-down and step-up transformers do the necessary adjustments to ensure that required voltage is available to the ESP. [6]

Figure II.5 Variable speed drive (6)

The VSD converts the input frequency (normally 60 Hz) into the required operating frequency, VSD contain the following main components:

- Rectifier section. Converts AC voltage and current into a DC voltage and current.
- DC control section. Provides a smooth DC waveform to the next section.
- Inverter section. Converts the DC voltage back to an AC voltage at a determined frequency.

VSD is widely accepted as an important tool to ensure operational flexibility of ESP systems.

VSD are commonplace in oil wells where down-hole conditions are subject to changes (applies to most oil wells). [7]

II.4.2 ***Downhole components***

II.4.2.1 ***Pump***

The heart of the ESP system is the submersible pump; to get an understanding of how the whole ESP unit functions it is important to understand the operation of the pump. This is why the description of the system components has to be started with a thorough analysis of the construction and operation of the pump. Pumps in the petroleum industry can be classified in two groups:

- Displacement pumps.
- Dynamic pumps.

Rod and PCP pumps are of the displacement type while ESP's work on the dynamic principle. ESP utilize submersible centrifugal pumps driven by electric motors, that convert the energy from the rotating shaft into centrifugal forces that lift well fluids to ,surface . [2]

Main features of centrifugal pumps in ESP systems:

- Multistage pumps.
- They have radial or mixed flow configurations.
- Operates in a vertical position.

The submersible pumps used in ESP systems have had a continuous evolution over the years but their basic operational principle remains the same. Well fluids, after being subjected to great centrifugal forces caused by the high rotational speed of the impeller, lose their kinetic energy in the diffuser where a conversion of kinetic to pressure energy takes place. [3]

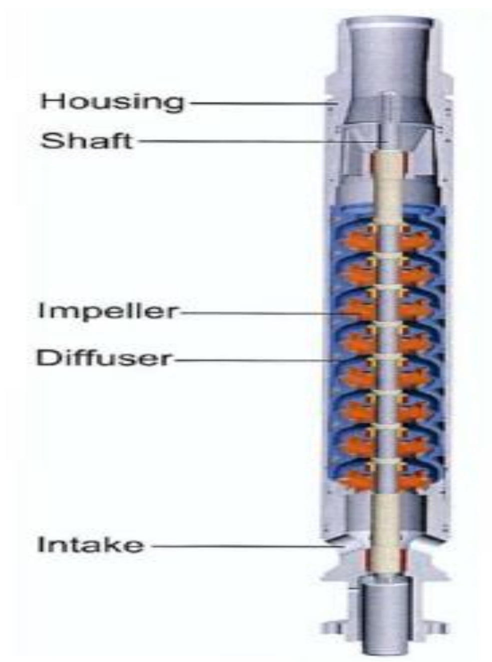


Figure II.6 Cut view of ESP (2)

Main components in the submerged pump:

II.4.2.2 *Impeller*

The impeller is locked to the shaft and rotates with the RPM of the motor. When the impeller rotates it transfer centrifugal force on the production fluid. (Figure II.7) is an illustration of an impeller keyed to a shaft, and sub-components of the impeller [3]. Two types of impeller designs are available; fixed and floating impellers**.**

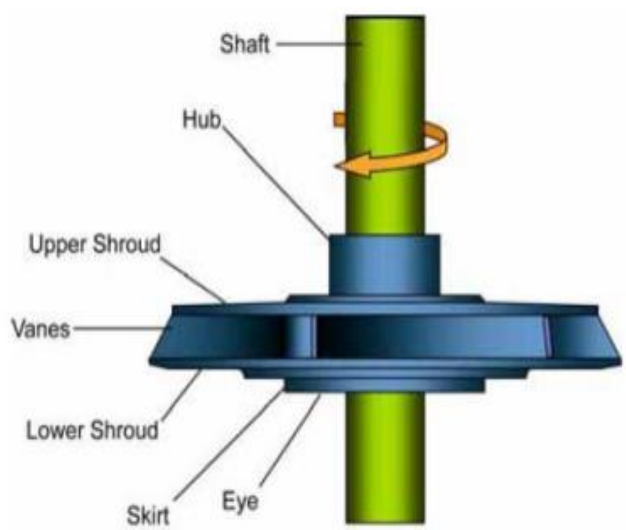


Figure II.7 impeller (2)

Fixed impellers Pumps with fixed impellers (also called compression pumps) have impellers locked in position in the shaft. The impeller hubs are in contact with each other so that they have no clearance to move axially. [3]

Floating impellers In pumps with floating impellers (also called floater pumps) are the impellers allowed to move axially between the diffusers, since the impeller hubs is not stacked on top of each other.[3]

II.4.2.3 *Diffuser and Pump Stage*

The diffuser turns the fluid into the next impeller and is stationary. Diffusers are contained within the pump housing and the required number of stages is reached by stacking the right number of diffusers and impellers on top of each other. [3]

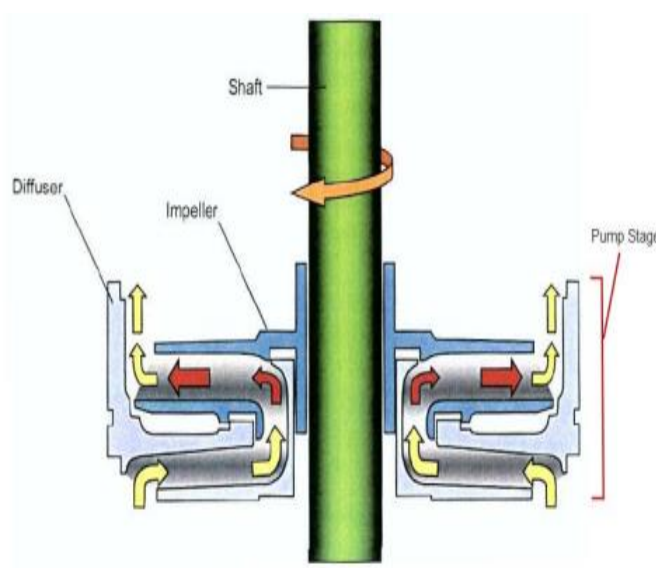


Figure II.8 Pump stage (diffuser) (2)

A pump stage is formed by combining an impeller and a diffuser.

II.4.2.4 *Performance Characteristics*

The manufacturers state the performance of their pump stages on the basis one stage, 1.0 specific gravity (SG) water at 60- or 50-Hz power. A typical performance curve for a 4-in.-diameter radial-style pump, with a nominal best-efficiency performance flow of 650 B/D with a nominal flow rate of 6,000 B/D is shown in (Fig II.9) In these graphs, the head, brake horsepower (BHP), and efficiency of the stage are plotted against flow rate on the x-axis. Head, flow rate, and BHP are based on test data, and efficiency is, calculated on the basis of**:** [2]

$$\text{efficiency} = \eta_p = [Q \times \text{TDH} \times \text{SG}] / (C \times \text{BHP})$$

Where:

Q is given in gal/min,	Or	Q is given in m3/d,
TDH is given in ft.		TDH = m,
C = 3,960;		C = 6,750

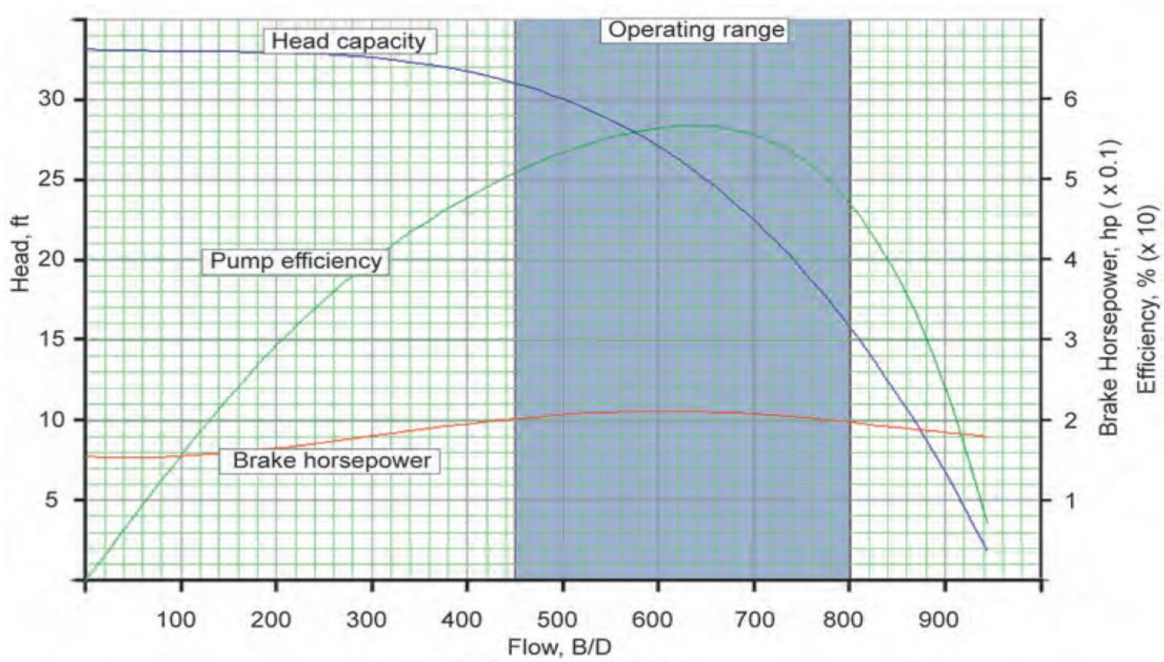


Figure II.9 Pump performance curve **(2)**

The head/flow curve shows the head or lift, measured in feet or meters, which can be produced by one stage. Because head is independent of the fluid SG, the pump produces the same head on all fluids, except those that are viscous or have free gas entrained. If the lift is presented in terms of pressure, there will be a specific curve for each fluid, dependent upon its SG. The dark (highlighted) area on the curve is the manufacturer's recommended "operating range." ROR It shows the range in which the pump can be reliably operated. The left edge of the area is the minimum operating point, and the right edge is the maximum operating point. The best efficiency point (BEP) is between these two points, and it is where the efficiency curve peaks. The shape of the head/flow curve and the thrust characteristic curve of that particular stage determines the minimum and maximum points. The minimum point is usually located where the head curve is still rising, prior to its flattening or dropping off and at an acceptable down thrust value for the thrust washer load-carrying capabilities. The location of the maximum point is based on maintaining the impeller at a performance balance based on consideration of the thrust value, head produced, and acceptable efficiency. [2]

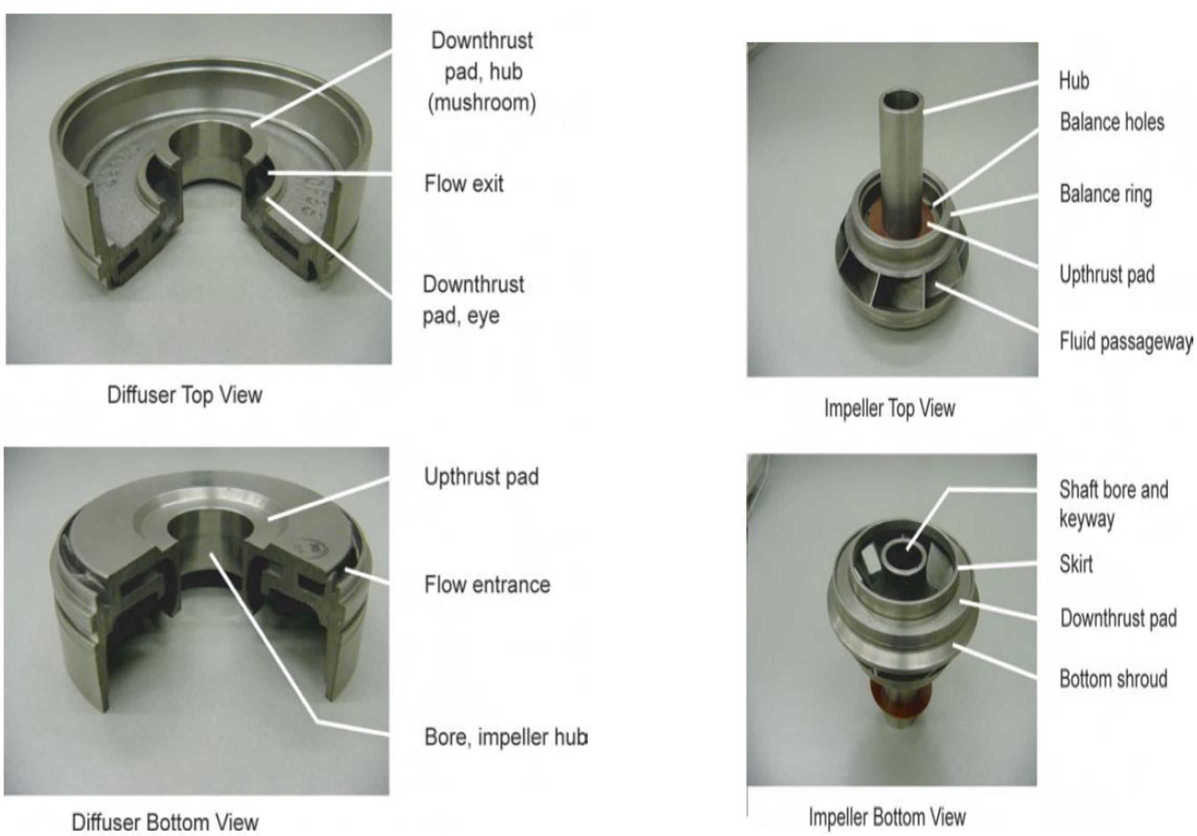


Figure II.10 Top / bottom view of diffuser + impeller (2)

II.4.2.5 *Shaft*

The pump shaft is connected to the motor (through the gas separator and seal section), and spins with the motor speed. The pump shaft turns the impeller with the help of keys fitted into the key-way of the impeller. [3]

II.4.2.6 *Intake*

The pump intake is attached to the lower end of the pump and provides a passageway for fluids to enter the flow capacity of the submerged pump depends on the following factors:

- ✓ The rotational speed provided by the motor.
- ✓ Diameter of the impeller.
- ✓ Design of the impeller.
- ✓ The actual head against which the pump is operating.
- ✓ Fluid properties (density, viscosity, etc.).

For constant speed ESP applications the most important factor is impeller size, which is limited by the ID of the well casing. Pumps with big impellers can produce larger liquid rates, although impeller design also has a significant impact on pump capacity. ESP pumps which are available today come in different capacities from a few hundred to around 80.000 BPD of production rate, and with OD diameters from around 3 -11 inches. Smaller pumps are used up to the rates of 1.500 – 3.500 BPD. For ensuring proper assembling and ease of handling, pump length are limited to about 6 – 8m. Up to three pump-sections can be connected together in series, to achieve higher operational heads usually required in deeper wells. Such an assembly can have several hundred pump-stages;

The maximum number of stages is limited by one or more of these factors:

- ✓ the strength of the pump shaft.
- ✓ the maximum burst-pressure rating of the pump housing.
- ✓ The maximum allowed axial load on the pump’s main thrust bearing.

Individual pump stages handle the same fluid volume and develop the same amount of head.

Head is a measure of the pressure exerted by the fluid, often in meter of bar. Each pump stage creates a certain amount of head in order to lift the fluid to surface. Head is created by utilizing the power generated by the motor and transferred through the shaft. The impeller rotates at the same speed of the shaft and transfer centrifugal energy to the fluid. The impeller forces the fluid to the outside of the stage where it exits the impeller and enters the diffuser of the next pump stage. The diffuser then redirects the fluid up into the next impeller and the process repeats. The head one stage produces is the net of the energy imparted by the impeller and the energy lost while passing through the diffuser. The head that one stage develops can then be multiplied by the number of stages to determine the total head that the pump will deliver. [3]

II.4.2.7 *Electric motor*

The main purpose of a motor is to convert electrical energy into mechanical energy that turns the shaft. The shaft is connected through the seal and gas separator and rotates the impellers inside the pump.

An ESP motor consists of the following major components:

- Rotors.
- Stator.
- Shaft.
- Bearings.
- Insulated Magnet Wire.
- Winding Encapsulation.
- Rotor and Stator Laminations.
- Housing.
- Bearing. [2]

***Figure II.11 Electric motor* (2)**

An ESP motor is a three-phase, two pole, squirrel cage induction-type electric motor. It work on the principle of the electromagnetic induction that states an electric current induced in any conductor moving in relation to a

ESP motors normally run at approximately 3600 RPM on 60 Hertz power systems. The operating voltage of ESP motors can vary from 230 – 7000 volt. By increasing the length or diameter of the motor the effect can be increased to achieve the required horsepower. But since we have a determined diameter in an oil well ESP motors are often made very long, maybe 10m to get enough power (Figure II.11) shows the basic construction of an ESP motor. The stator which is connected to the housing is a hollow cylinder made up of a great number of tightly packed steel discs called stator laminations. This solution prevents that eddy-currents are occurring in the metal of the stator. Inside the laminations there are several slots which accommodate the insulated copper stator windings called “magnet wire” connected to the AC power. Along the perimeter of the motor there are three pairs of coils [3]. To make sure that no electrical failures are occurring in the windings, the motor must have an insulating system which include:

- insulation of the individual wires making up the windings.
- insulation between the stator and the windings.
- protection against phase-to-phase faults.[3]

The rotor consists of rotor laminations and is located inside the stator, separated from it by an annular air gap. The slots of rotor laminations contain a set of copper bars making up the squirrel cage. The center bore of the rotor laminations has an axial keyway that accepts the key that connects the laminations to the motor shaft and allows transmission of torque to the shaft. Because of high rotational speeds, the rotors are made up of short segments with radial bearings between them. The rotating magnetic field developed in the stator windings induces a current in the rotor which creates a magnetic field. The interaction of the two magnetic fields turns the rotor and drives the motor shaft, which again are connected to the pump impellers.

A motor shaft can be up to 10 m long, it is therefore crucial to eliminate radial vibrations. This is why there are radial bearings located at several places along the shaft’s length. The motor is filled with refined oil that provides dielectric strength, lubrication, and cooling. The motor shaft is hollow to allow the oil to circulate, and a filter is provided to remove solid particles from the oil.

Electric motors used in ESP are very different from “normal” motors which is common on the surface, the most important differences are:

- their length to diameter ratio is much greater than surface motors.
- they are cooled by the well fluid and not surrounding air.
- they are connected to the surface power source by long cables, [3]

Where a substantia voltage drop can occur as mentioned earlier the only way to increase motor power is to increase the length of the motor. But it is possible to connect two or three motors in tandem to achieve higher power ratings,
see (Figure II.12), the two motors are mechanically coupled but work independently in an electrical sense. Motor power can reach 2.000 HP, allowing the production of 30.000 BPD. [3]

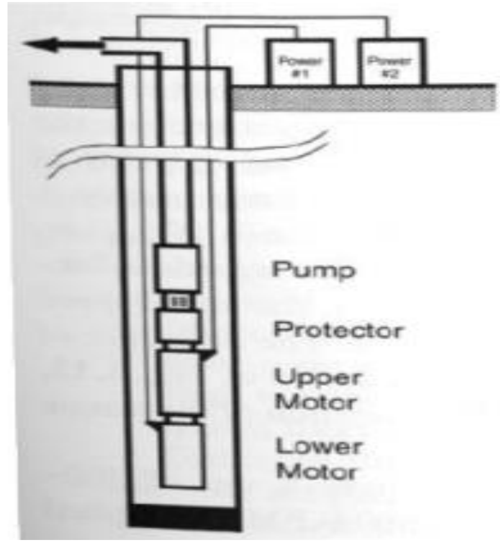


Figure II.12 Tandem motor connected to ESP (3)

II.4.2.8 *Gas separator*

If free gas is allowed to enter a centrifugal pump it will deteriorate its performance. This is, because it is a great difference between the specific gravity of liquid and gas The amount of kinetic energy passed on to the fluid in a centrifugal pump, greatly depends on the fluid density. Since liquid is denser than gas, it receives a great amount of kinetic energy that after conversion in the pump stage, increases the pressure. Gas however, although being subjected to the same rotational speed, cannot generate the same amount of pressure increase.

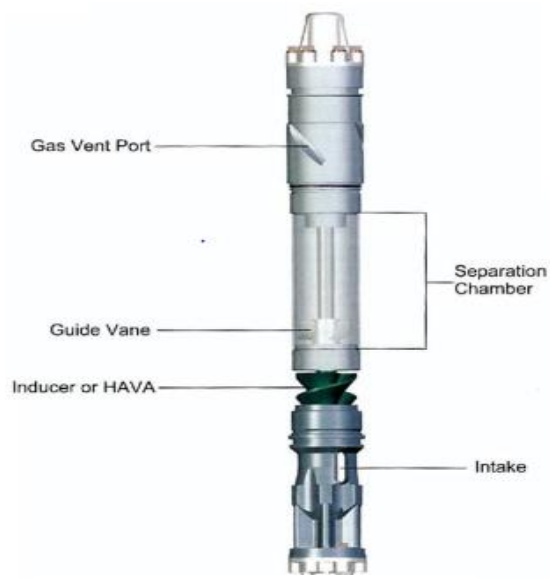


Figure II.13 Gas separator (3)

This is why ESP pumps always should be fed by single phase well fluid to ensure reliable operation. [3]

Pumping of well fluids with free gas can have the following effect on the ESP pump:

- The head developed by the pump decreases.
- The output flow fluctuates; cavitation can occur at higher flow rates causing damage to the pump stages.
- In wells with extremely high GOR, gas locking may occur.

In wells with high GOR, gas separators replace standard pump intakes and helps improve pump performance by separating a portion of the free gas before it enters the first stage. This helps gas locking from occurring and improve the reliability of ESP systems. The most common separator type used in ESP is rotary gas separators, see (Figure II.13). [2]

They work on the principle that a multiphase fluid, if spun at high speed is separated to liquid and gas phases because of the different levels of centrifugal force acting on the liquid and gas particles. The rotational spin is provided by the separator shaft which is driven by the motor.

Separation takes place in the separator chamber. Where the heavier fluid is being forced to the outer wall in the chamber and the lighter gas gathers along the shaft. Then the gas is being directed into the casing annulus and the liquid is being directed to the pump intake Typical separator efficiencies is 80% or higher, this efficiency is affected by flow rates, viscosity, and percentage of free gas vs. total volume produced. In extremely high gas conditions, tandem gas separator assemblies can be used to further improve the separator efficiency. [3]

Statoil have to comply with Norwegian regulations that requires that no gas should be vented through the casing annulus, this is because of safety barrier issues. Thus Statoil have to use a form for separator that does not direct free gas into annulus but still manage to separate the gas from the well fluid.

One such method is Schlumberger advanced gas handler called Poseidon, shown in (Figure II.14).

Figure II.14 Poseidon SLB gas handler (3)

This makes use of a gas handler utilizing special pump stages originally devised for transferring multiphase mixtures. Poseidon contains impellers with helio-axial vanes and diffusers providing a smooth axial flow. This method ensures an almost homogeneous distribution of gas particles in the fluid. Poseidon can either be connected above a gas separator when gas is allowed to travel up annulus, or it can be connected above a standard intake if the gas has to go through the pump [8]. The unit can handle well-streams with up to 75% of free gas content. It can handle flow ranges between 5.000 BPD and 9.000 BPD and need a substantial power of 50 HP to operate. [2]

II.4.2.9 *Seal Section*

Main components in a Seal Section:

- Mechanical Seals
- Elastomer Bags
- Labyrinth Chamber
- Thrust Bearing

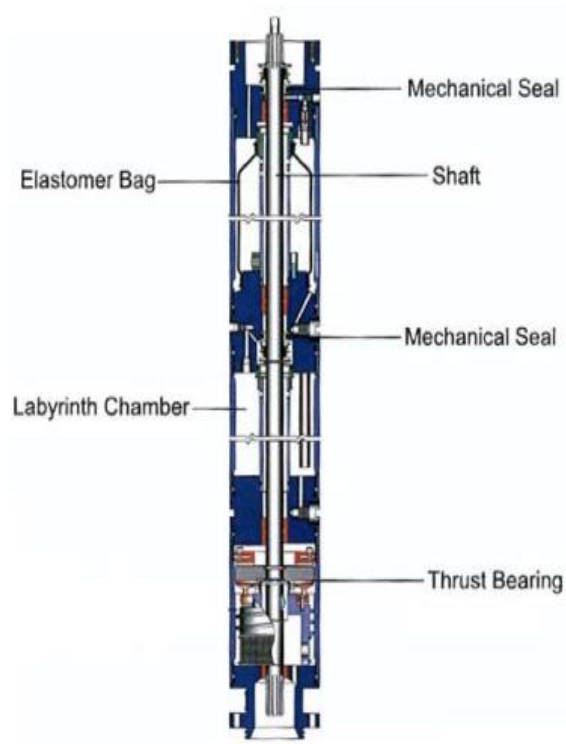


Figure II.15 Seal section (2)

The seal section connects the motor shaft to the gas separator shaft. Seal sections also perform four crucial functions:

1. It allows for expansion and contraction of the motor oil. High well temperature and heat generated in the motor itself causes the motor oil to expand. Since the seal is connected directly to the motor, the expanding oil is allowed to enter the seal during normal operation. During shutdowns, the oil in the motor shrinks because of the decreased motor temperature and part of it previously stored in the seal is sucked back to the motor. The bag and labyrinth help accomplish this function.

2. The seal equalizes the inside pressure with the surrounding annulus pressure. This equalization keeps well fluid from leaking into the motor. Well fluids which get into the motor can cause dielectric failure and loss of lubrication. Well fluid is allowed to migrate

into the top chamber of the seal section equalizing the pressure within the unit. The well fluid is contained in the upper chamber and cannot migrate into lower chambers.

3. It isolates the clean motor oil from well fluids. The seal contains several shaft seals that prevent well fluid from leaking down the shaft. A rubber bladder acts as a positive barrier to the well fluid. The labyrinth chambers separate motor oil and well fluids based on the difference in densities between the two liquids.

4. It provides the mechanical connection between the motor and the pump, and absorbs the thrust load produced by the pump. This is accomplished by the thrust bearing, which must be capable of overcoming the net axial force acting on the pump shaft. [3]

II.4.2.10 *Power cable*

The ESP cable transfer electric power from the surface power source to the motor and act as the critical link between surface and the down-hole equipment. The cable is a three phase electric cable that runs down the production tubing. ESP cables operate in harsh conditions and must meet the following requirements:

- ✓ They must have a small diameter so they fit in the casing annulus.
- ✓ They must retain their dielectric properties when subjected to hot liquids and gasses
- ✓ They must be well protected against mechanical damage. [2]

ESP cables can be made in both round and flat configurations. Most cables are composed of the following components:

- ✓ Three copper conductors carrying the AC current.
- ✓ Individual insulation of each conductor preventing short circuits and current leakage.
- ✓ A jacket which provides the structural strength and protection, and prevents contact of the insulations with the down-hole equipment.
- ✓ A metal armor providing improved mechanical protection.

Because of the very unforgiving conditions in oil wells, cables must be durable in a wide range of conditions. Long cable life is best achieved by preventing decompression, and mechanical damage resulting in durable long lasting ESP cables. [2]

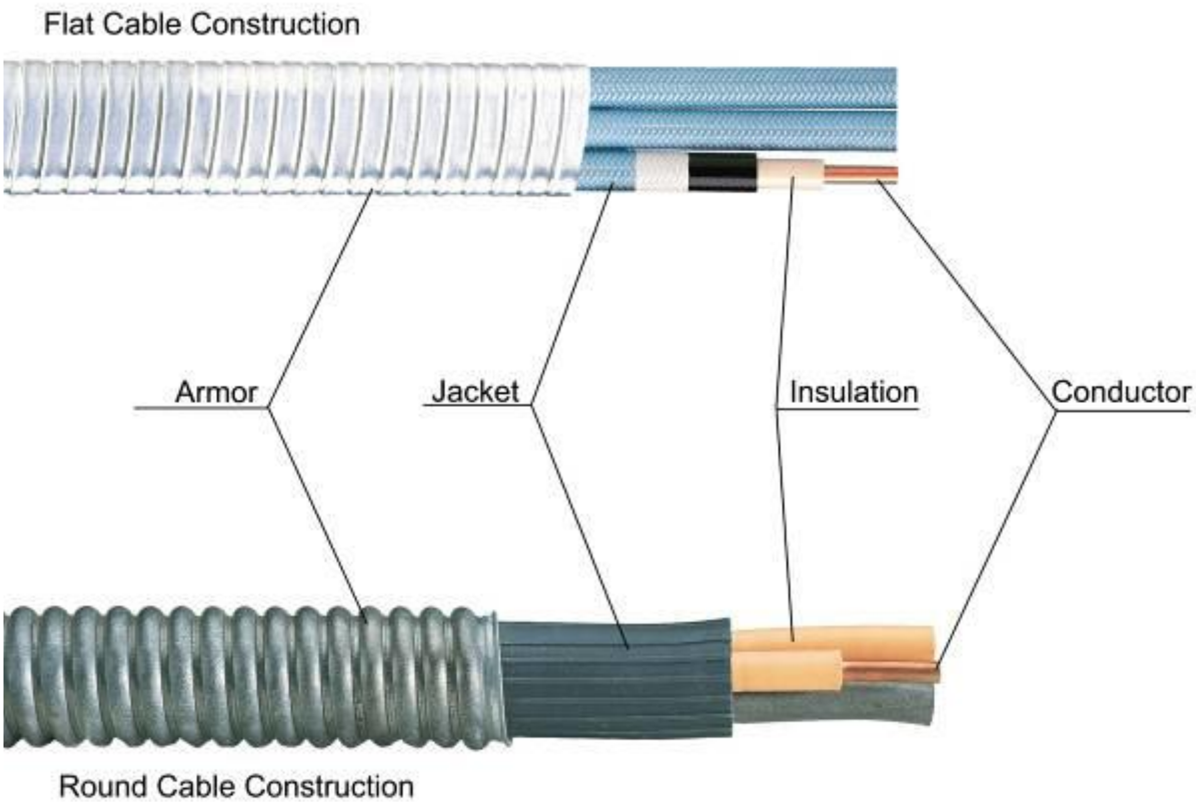


Figure II.16 ESP cable (2)

Chapter III. Case Study of ESP well (SFNE13) on BRN field

CHAPTER II: CASE STUDY OF ESP WELL ON BRN FILED

III.1 Nodal Analyses

Fluid flows from the reservoir to the stock tank because of the pressure gradients within the system. The total pressure drop from the reservoir to the separator is the sum of the individual pressure drops through four different segments: in the reservoir, across the completion, up the wellbore, and through the flow line.

It is relatively straightforward to calculate the pressure drop for each of these segments, if we know the flow rate and either the upstream or downstream pressure, and the physical properties of the segment.

How do we calculate the flow rate, knowing the reservoir and separator pressures? This is the central question of Nodal Analysis. To simulate the fluid flow in the system, it is necessary to "break" the system into discrete **nodes** that separate system elements. [8]

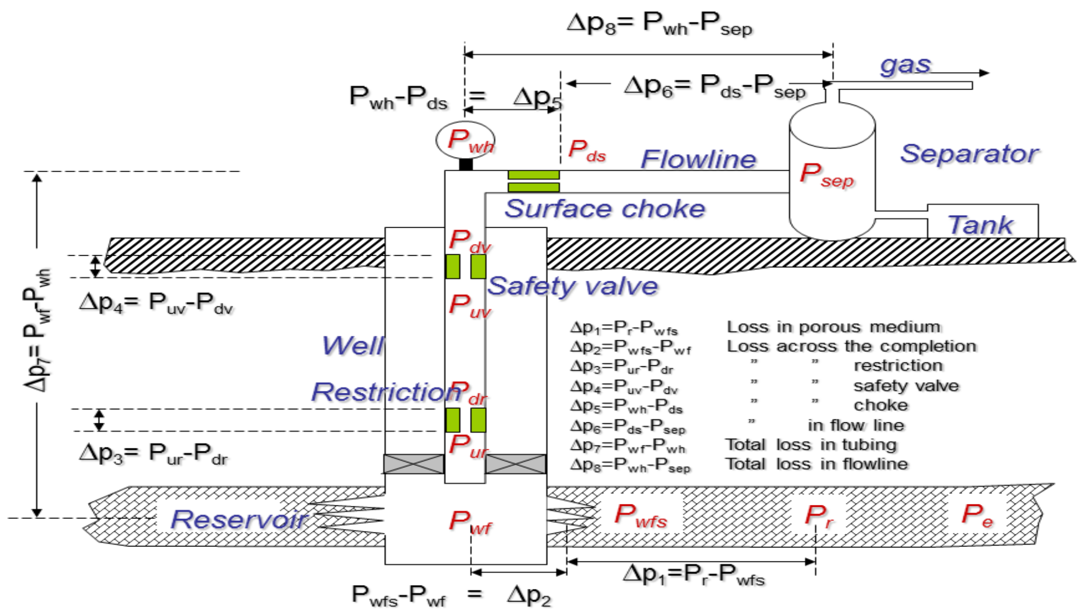


Figure III.1 Pressure drop during production (8)

We start in the reservoir at the average reservoir pressure, P_r, and assume a flow rate. This lets us calculate the pressure just beyond the completion, Pwfs. We can then calculate the pressure drop across the completion, and the bottom-hole pressure Pwf. [8]

This pressure is valid only for the assumed flow rate .Or; we may start at the separator at Psep, and calculate the pressure drop in the flow line to find the wellhead pressure, Pwh.

Then we can calculate the bottom-hole pressure Pwf. Again, this pressure is valid only for the assumed flow rate. [8]

The two calculated bottom-hole pressures will probably not be the same. If not, then the assumed rate is wrong. “Nodal” analysis refers to the fact that we have to choose a point or “node” in the system at which we evaluate the pressure - in this case, the bottom of the wellbore. This point is referred to as the solution point or solution node. [8]

III.1.1 *Inflow performance curve*

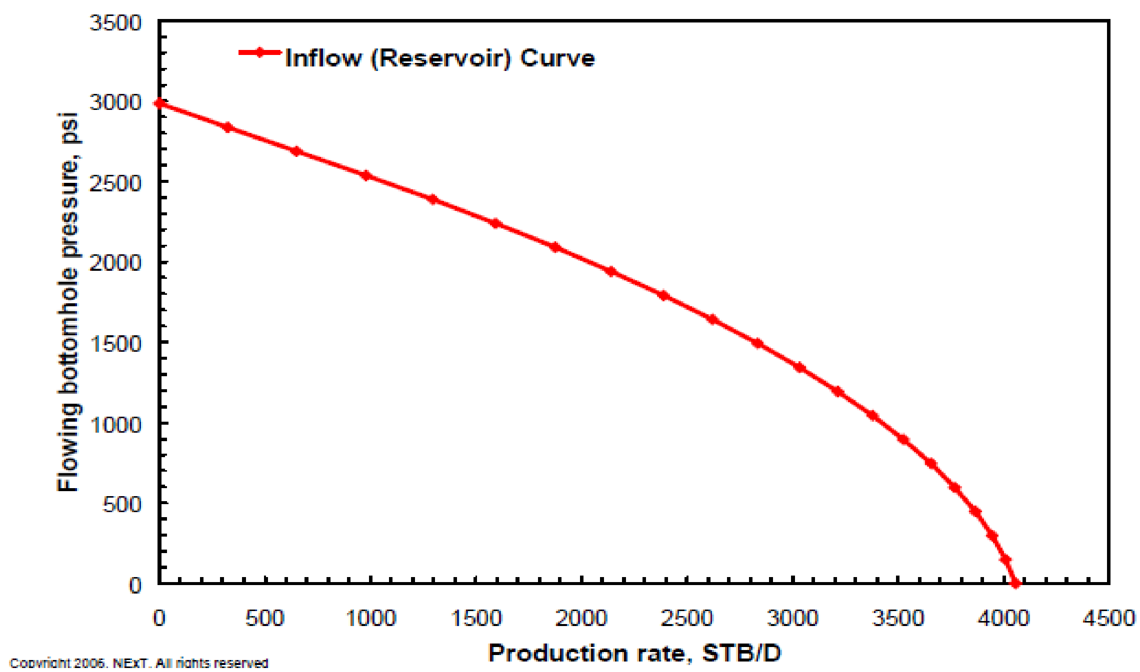


Figure III.2 inflow performance curve (9)

Let's assume that the well is completed open hole, and that the well is neither damaged nor stimulated. In this case, the pressure drop across the completion is zero. For the moment, we ignore the wellbore and the flow line.

If the flow rate is 0, the bottom-hole pressure P_{wf} will be the same as the average reservoir pressure, p_r. As we increase the flow rate, the pressure drop in the reservoir segment increases - causing the bottom-hole pressure P_{wf} to decrease. When we graph the flowing bottom-hole pressure as a function of flow rate, the result is a curve intersecting the y-axis at the initial reservoir pressure, and intersecting the x-axis at the maximum rate the well would produce if opened to the atmosphere at the perforations. This curve is usually referred to as the "inflow curve" or the "reservoir curve". Until we take into account the pressure drop within the wellbore, this curve tells us very little about the rate at which the well will produce for a given wellhead pressure. [9] Inflow Performance depends on the following:

✓ **OIL:**	✓ **GAS:**
-Viscosity, GOR, Bubble Point Pressure (Pb)	-Viscosity, Z Factor, Compressibility
-Formation Volume Factor (Bo), Density	-Formation Volume Factor (Bg), Density

- ✓ **Inflow Correlation used**: OIL (*Darcy, Vogel*), GAS (*Jones, Darcy*)
- ✓ **Well Geometry: vertical**, deviated, horizontal
- ✓ **Formation Properties:** Reservoir Pressure, Total Skin, Permeability, Net Pay

Vogel was the first to present an easy to-use method for predicting the performance of oil wells. His empirical inflow performance relationship (IPR) is based on computer simulation results and is given by

$$\frac{Q_o}{Q_o max} = 1 - 0.2\left(\frac{\text{pwf}}{\text{pr}}\right) - 0.8\left(\frac{\text{pwf}}{\text{pr}}\right)^2 \text{..................................} (2)$$

III.1.2 *Outflow curve*

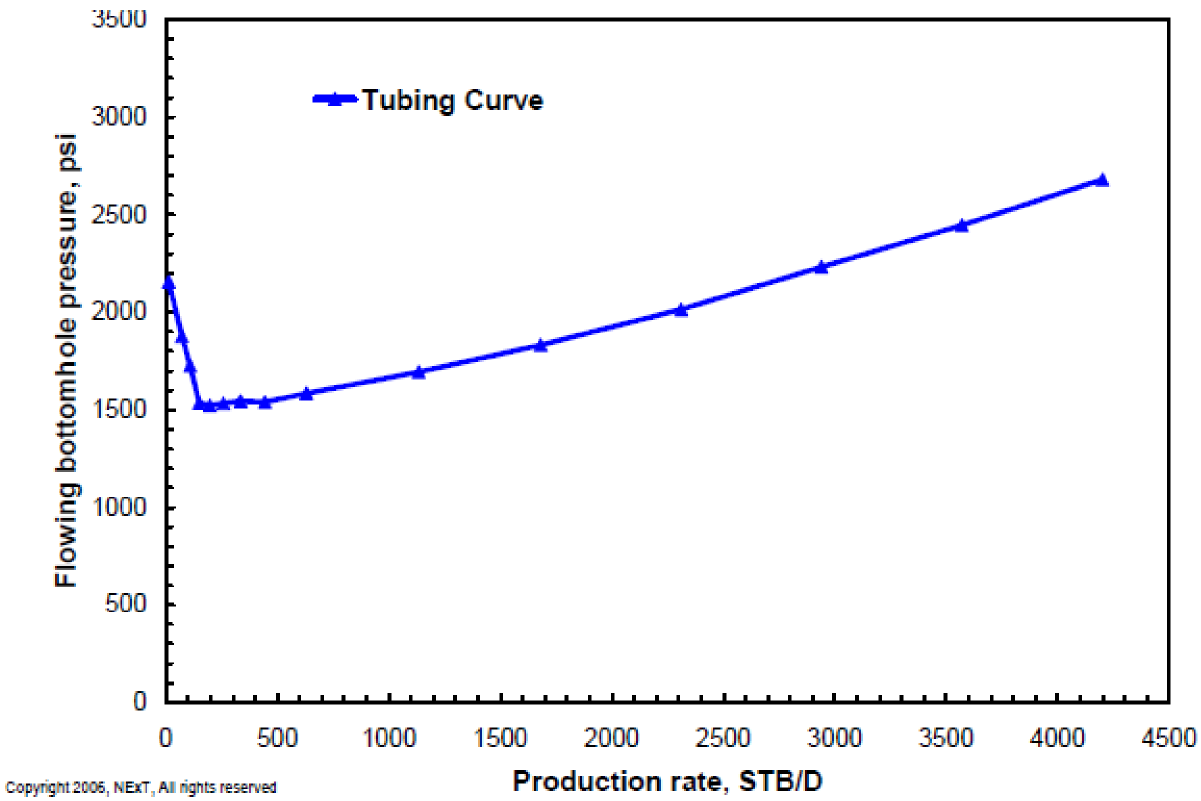


Figure III.3 outflow curve (9)

This curve is usually referred to as the "outflow curve" or the "tubing performance curve". Until we take into account the reservoir behavior, this curve also tells us almost nothing about the rate at which the well will produce. [9] Outflow Performance depends on the following Fluid Properties

- ✓ **OIL:**

Viscosity, GOR, Bubble Point Pressure (Pb)

Formation Volume Factor (Bo), Density

- ✓ **GAS:**

Viscosity, Z Factor, Compressibility

Formation Volume Factor (Bg), Density

- ✓ **Outflow Correlation used**: OIL (*Duns & Ros, Beggs & Brill*), GAS (*Gray*)
- ✓ **Friction**
- ✓ **Completion Properties:**
- ✓ **Tubing's:** Size, Restrictions, Roughness
- ✓ **Chokes, flow line losses**

III.1.3 *System graph*

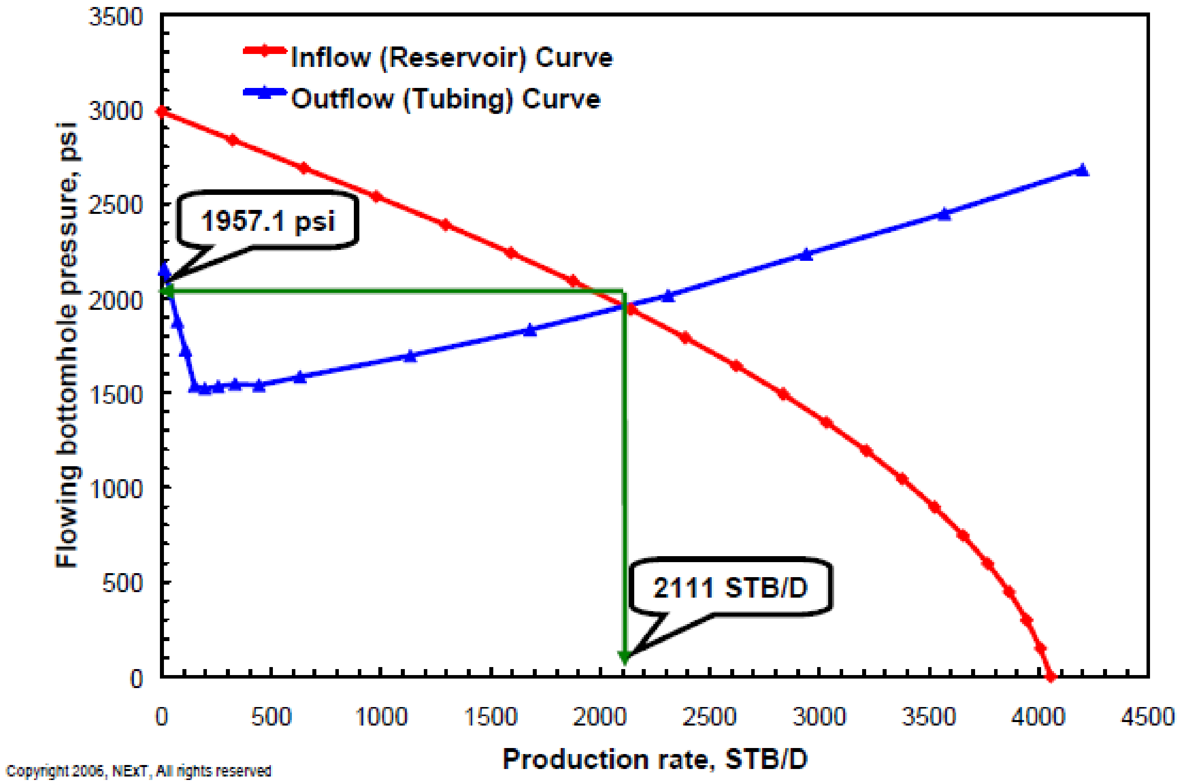


Figure III.4 System graph (9)

The **inflow** curve describes the relationship between the Bottom-hole pressure and the flow rate for the reservoir.

The **outflow** curve describes the relationship between the Bottom-hole pressure and flow rate for the wellbore.

When we graph these two curves on the same graph, we refer to this as the "system graph". The intersection of the inflow curve and the outflow curve gives the one unique flow rate at which the well will produce for a specified set of reservoir and wellbore properties.

The intersection of the two performance curves define the operating point, that is, operating flow rate and pressure, at the specified node.

For the convenience of using pressure data measured normally at either the bottom-hole or the wellhead, Nodal analysis is usually conducted using the bottom-hole or the wellhead as the solution node. [9]

The most noteworthy well performance programs on the market today are:

- **I.** Prosper (Petroleum Experts)
- **II.** WellFlo (Edinburgh Petroleum Services)
- **III.** Perform (Dwight's / IHS Energy Services)
- **IV.** PipeSim (Schlumberger)
- **V.** WEM (P.E. Mosely& Associates)

III.1.4 *Modeling software: PROSPER*

Petroleum Experts Limited's advanced **PRO**duction and **S**ystems **PER**formance analysis software

Petroleum Experts Limited's was founded by the Algerian **Abdelhamid Guedroudj.** Chief executive Abdelhamid Guedroudj has built this firm from a start-up in 1990 to international sales of £34 m in 2013. The Edinburgh business develops software that helps energy firms model production and maximize the extraction of oil and gas. It has now grown beyond its traditional markets in the US and Europe, and is expanding in the Middle East, Africa and South America. All members of the team (just 60 Engineer) have been involved in the development of software engineering products, as well as having extensive experience in petroleum engineering. [10]

And this statement was quoted from the website of the company "Petroleum Experts has over 420 clients worldwide. In fact, more than 80% of the revenue comes from outside Europe. The company is recognized across the international oil and gas industry as the technical market leader within its area of expertise and has been ranked number one in all technical evaluations across the industry for more than eight years". [10]

PROSPER is one of **PETX** products ,it can be used to model reservoir inflow performance (IPR) for single, multilayer, or multilateral wells with complex and highly deviated completions, optimizing all aspects of a completion design including perforation details and gravel packing. PROSPER can be used to design, optimize and troubleshoot gas lifted, ESP or other pump equipped wells. PROSPER sensitivity calculations allow the engineer to model and optimize tubing, choke and surface flow line performance for our case study we will use this software to design and modulate the ESP pump and make sensitivity calculations [11]

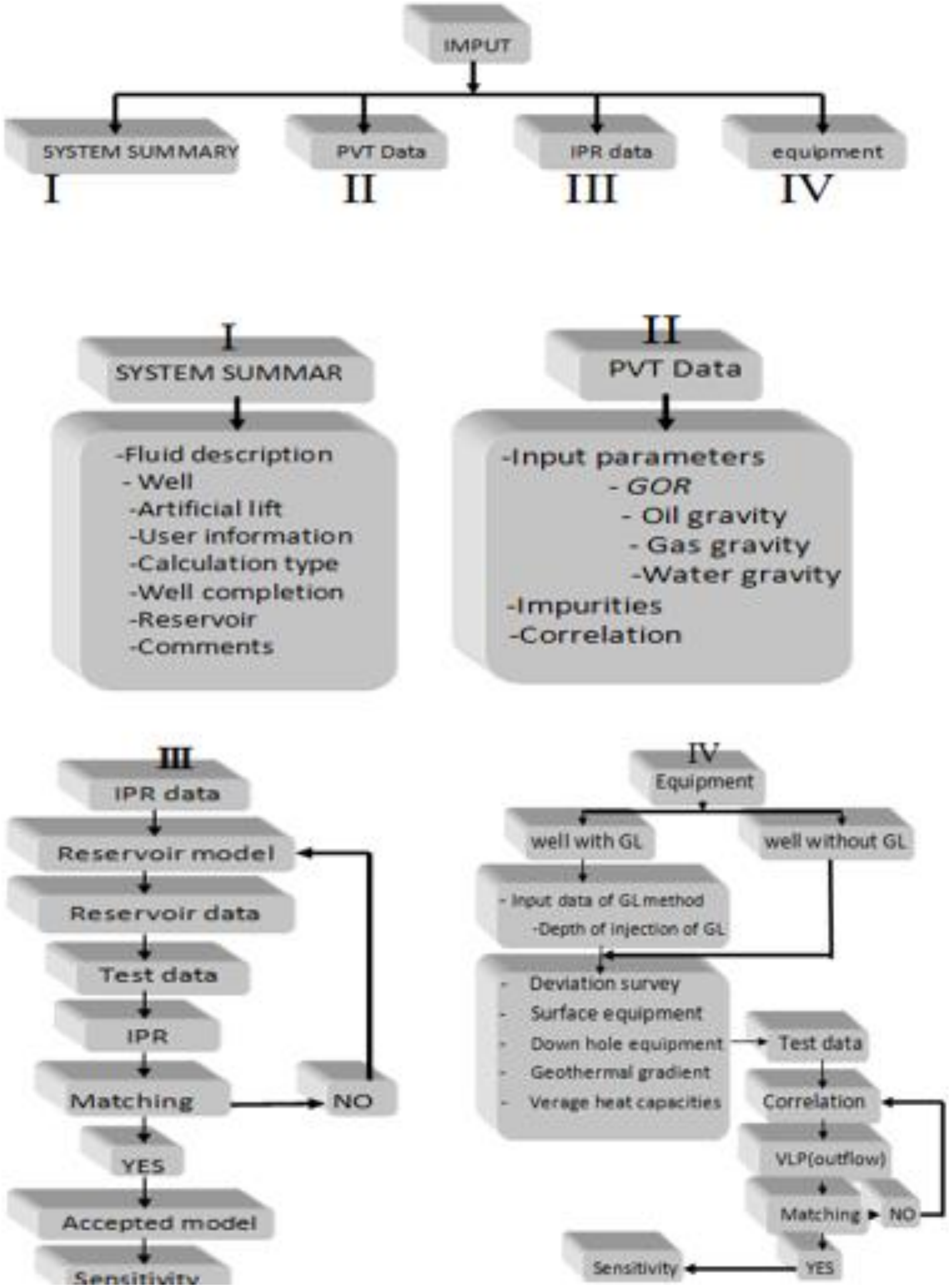


Figure III.5-PROSPER Operational Flowchart(11)

III.2 BRN field

The Groupement Sonatrach-AGIP is joint venture represents the first association between SONATRACH and a foreign company AGIP (ENI group (Italy)) for the exploitation of hydrocarbon deposits in the field of Bir Rebaa North area, Created under a hydrocarbons law signed in 1986 allowing foreign oil companies to explore the Algerian subsoil and to associate in the exploitation of fields for periods of 20 years and more. The group association contract has duration of 25 years. The BRN field is located on east of Hassi Messaoud at about 310 Km.

The GSA-BRN CPF (central processing facility) initially contained a single production line (train) with a processing capacity of 40,000 Bbl / d.

Then, the unit evolved with the establishment of a second train in 2002 with a capacity of 39,000 Bbl / d, and finally a third train in 2005 processing an average of 84,000 Bbl / d.

The daily production reach the on 2012 its maximum peak @ 110 000 BOPD[12]

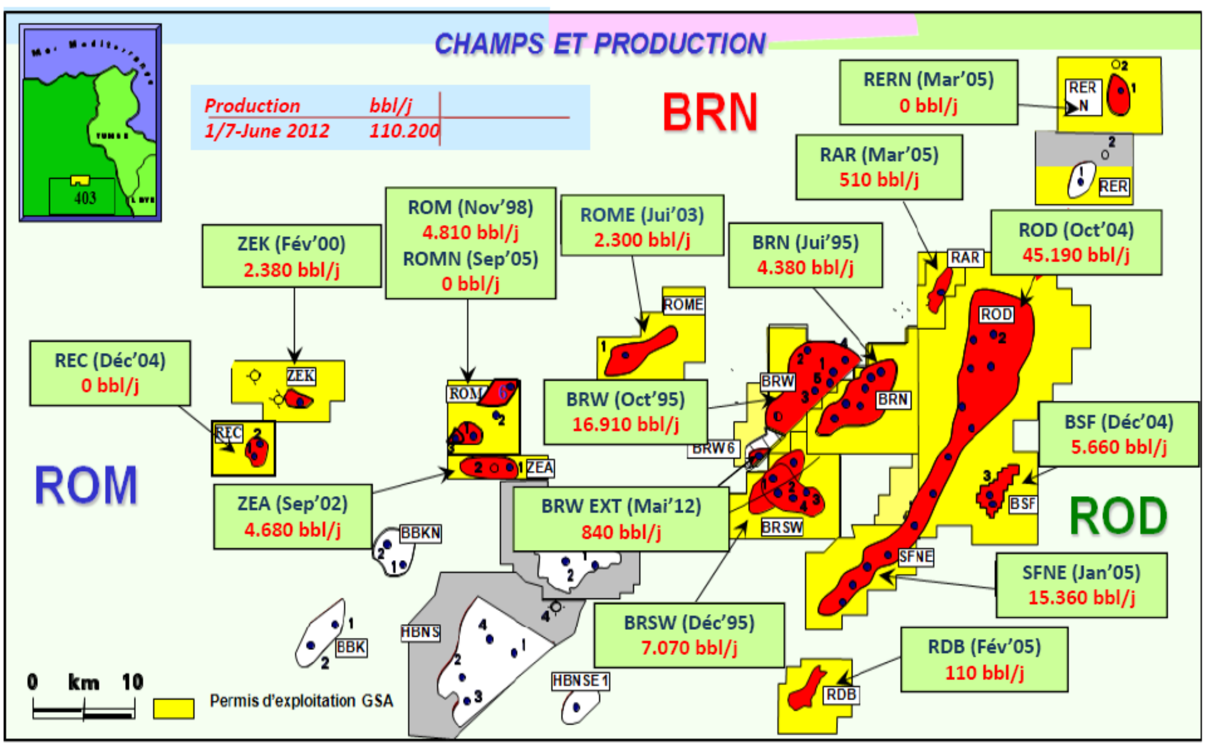


Figure III.6 BRN filed map (12)

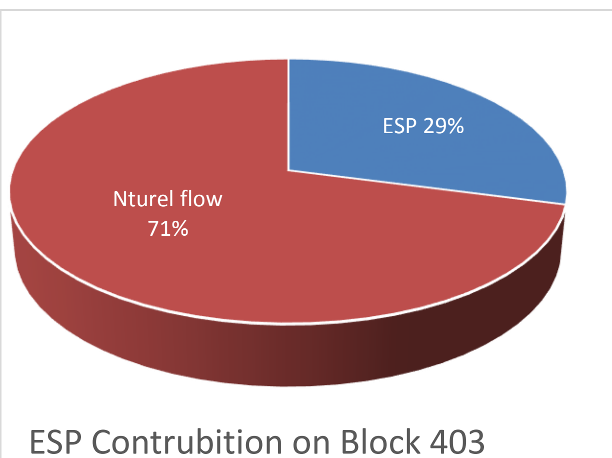
III.3 ESP on BRN

On 2006 GSA completed the first well with ESP and since that the number of ESP wells increasing, the Engendering tam have almost an experience of more than 12 years in the field of artificial lift specially the ESP

Here below some statistics about the ESP on BRN field

Table III-1 ESP wells statistics on BRN field (12)

Remarks	BLOC 403-403a-403d	BLOC 401a-402a	TOTAL GSA	Date
Total production	25 636	54 993	80 629	20 October 2017
ESP production	7 459	0	7 459	20 October 2017
Natural production	18 177	54 993	73 170	20 October 2017
ESP contribution (%)	29%	0%	9%	20 October 2017
Natural flow contribution (%)	71%	100%	91%	



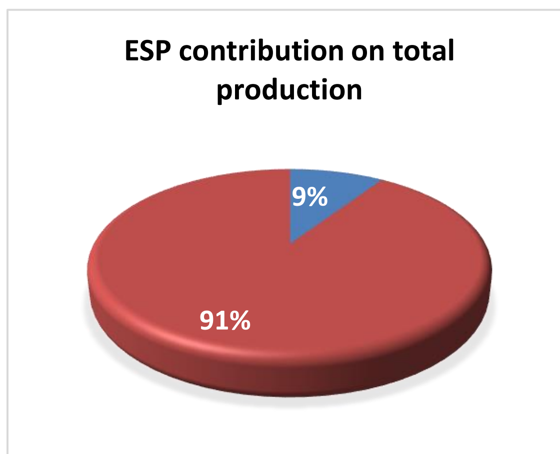
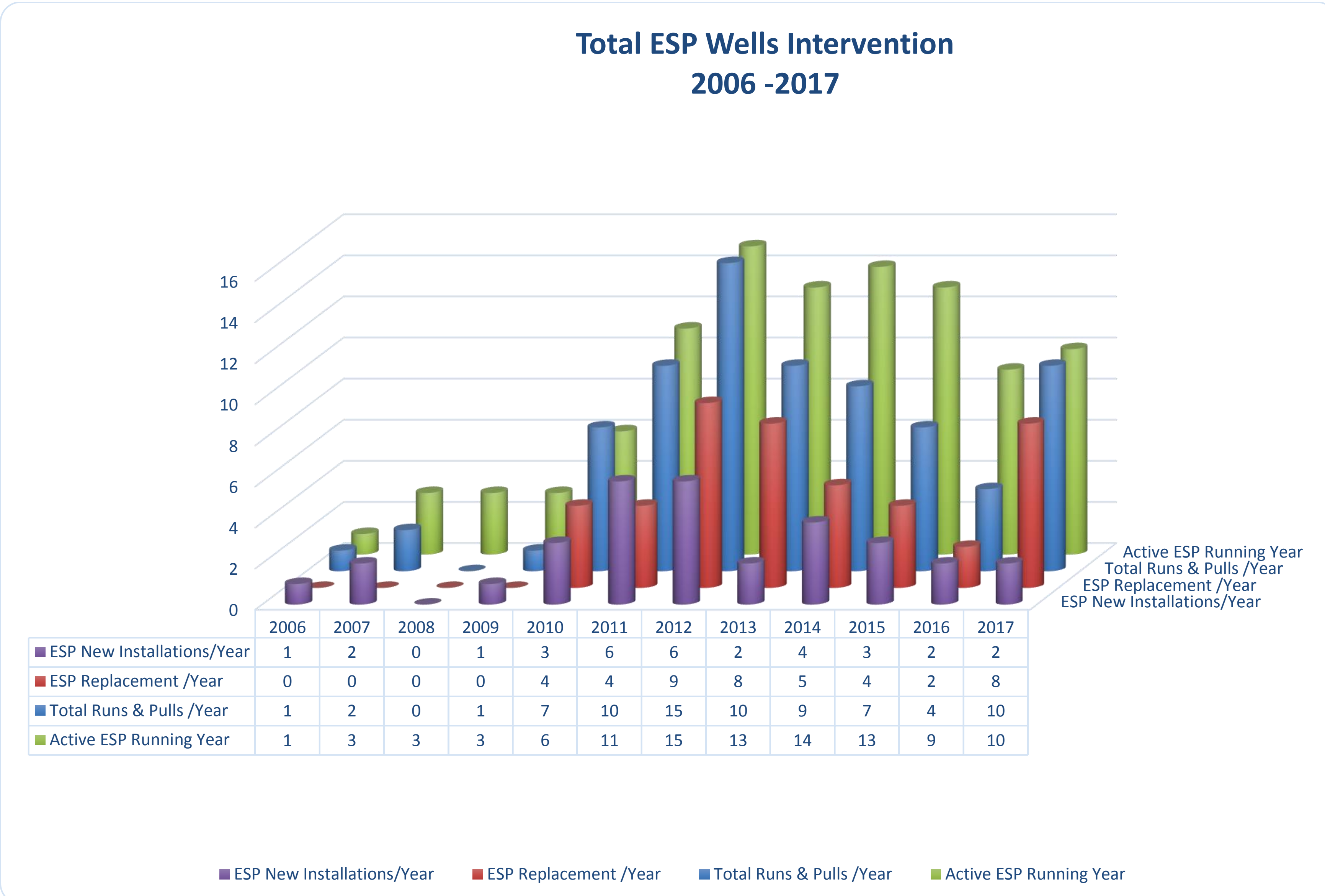


Figure III.7 ESP production contribution on BRN field (12)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
ESP New Installations/Year	1	2	0	1	3	6	6	2	4	3	2	2
ESP Replacement /Year	0	0	0	0	4	4	9	8	5	4	2	8
Total Runs & Pulls /Year	1	2	0	1	7	10	15	10	9	7	4	10
Active ESP Running Year	1	3	3	3	6	11	15	13	14	13	9	10

Figure III.8 Total ESP Wells Intervention (12)

From the ESP's statistics chart, the first ESP was installed on 2006 and from that year that number of new installation is increasing, till 2014 the year of the fall of oil price, and for economic limitations GSA decide to minimize the expenses on any drilling or workover activities

III.4 The history of SFNE 13

As part of the Sif Fatima North Est field development plan, the well SFNE-13 was drilled for the Upper and Lower TAG-I (Trias Argilo-Gréseux Inf.) oil production. The purpose of the well is to develop the southern part of the field. The drilling began on November 23, 2008 and ended on December 24, 2008 at depth final of 3065 m T.R.

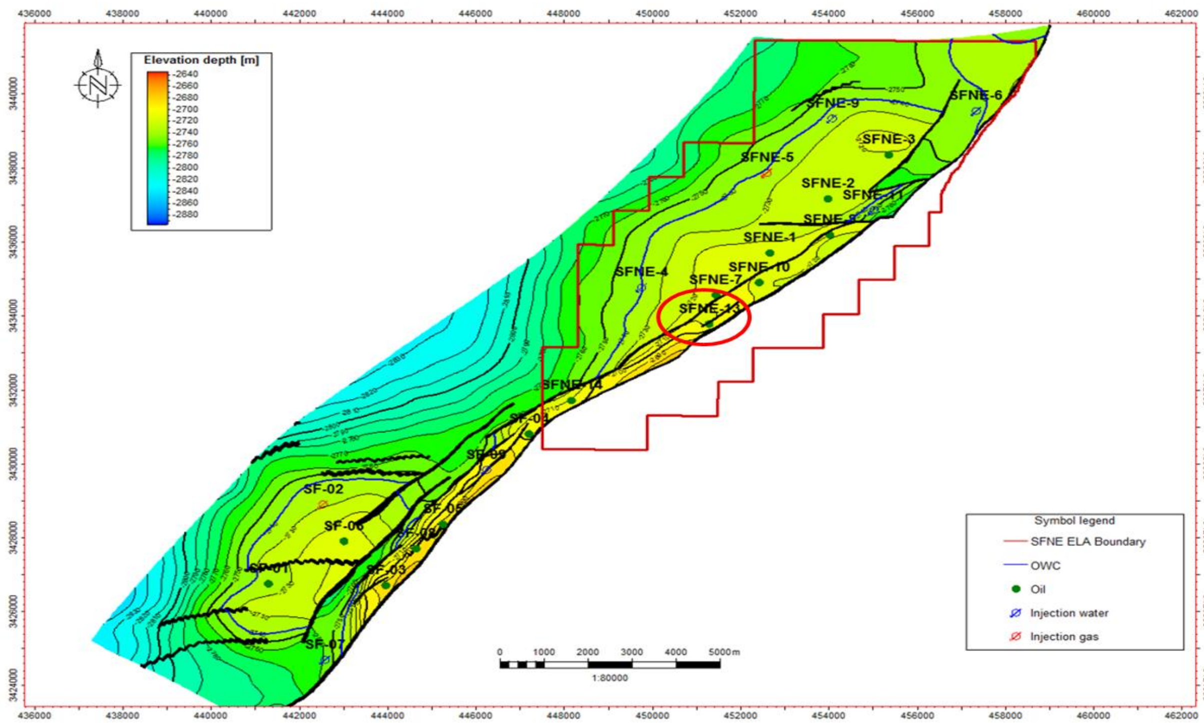


Figure III.9 Reservoir map of SFNE field (12)

SFNE 13 was completed in Middle TAGI (2,952 -2,958 m) and it is start producing on 05/03/2009

The Well shut-in on 21/03/2013 from Algerian authorities for its interference with SF field [12]

III.5 Operations to maintain well production

- On 07/07/2016 SFNE-13 restarted again producing from Middle TAGI. Since start-up, WC started to take place and increased gradually from 28% to 44%
- On 11/08/2016 SFNE-13 shut-in due to Train #03 shutdown. After shut-in, different attempts to restore well production were negative
- On 26/08/2016, Upper TAGI perforations extension were done (2936 – 2948 m). After perforating Upper TAGI, WC decreased to 27% due to anhydrous oil coming from Upper TAGI level (confirmed by PLT in October 2016).
- Starting from February 2017, well performance has been worsening due to increase in water production. Several cleanout jobs using coiled tubing were done to restore well production

By time, water production started to increase also in Upper TAGI, up to 25% (as per PLT in March 2017) [12]

Table III-2 PLT results

19/10/2016

Zones		Perforations		Qo	Qw	TOTAL PROD
		m	m	%	%	%
UPPER TAGI	Inf.1	2936	2948	70.0	0.0	49.4
MIDDLE TAGI	Inf.2	2952	2958	30.0	100.0	50.6

06/03/2017

Zones		Perforations		Qo	Qw	TOTAL PROD
		m	m	%	%	%
UPPER TAGI	Inf.1	2936	2948	73.4	25.1	56.1
MIDDLE TAGI	Inf.2	2952	2958	26.6	74.9	43.9

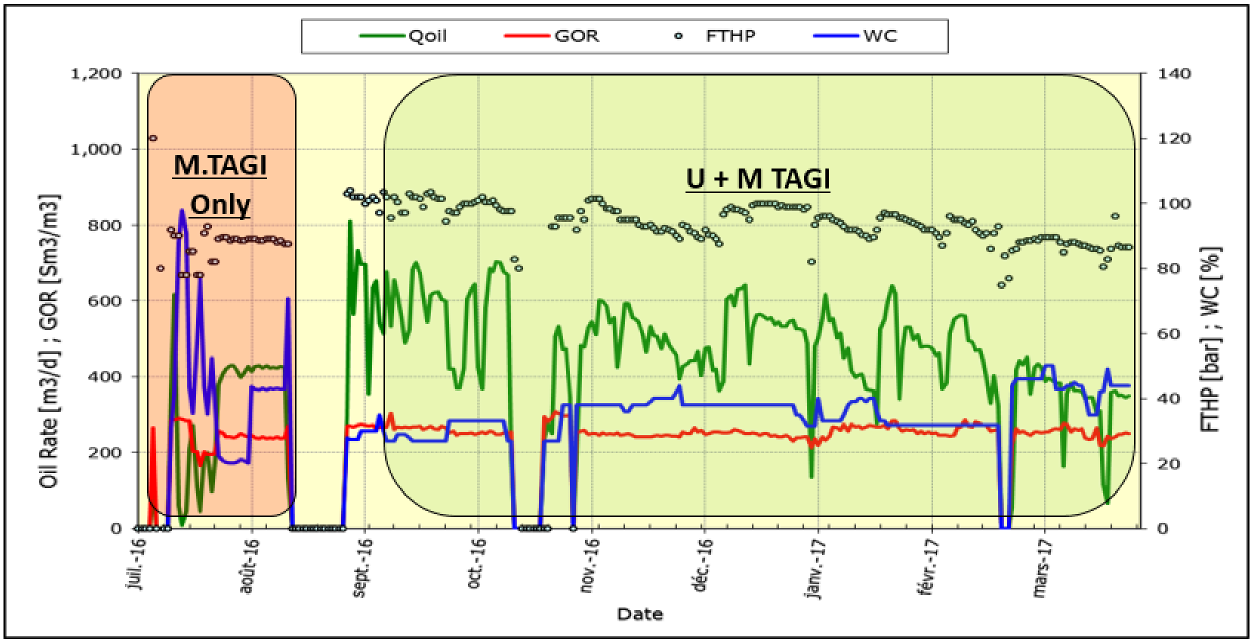


Figure III.10 Production before and after new perforations (12)

- On 05/04/2017 Copperhead 4 ½" Bridge plug was set @ 2949.4 m (tag top of plug) in order to isolate Middle TAGI
- Middle TAGI isolation has been successful, since the production test of 08/04/2017 (at FTHP 109 bar) registered oil production of 2500 Sbopd and WC 8% (vs. 40% pre-isolation)

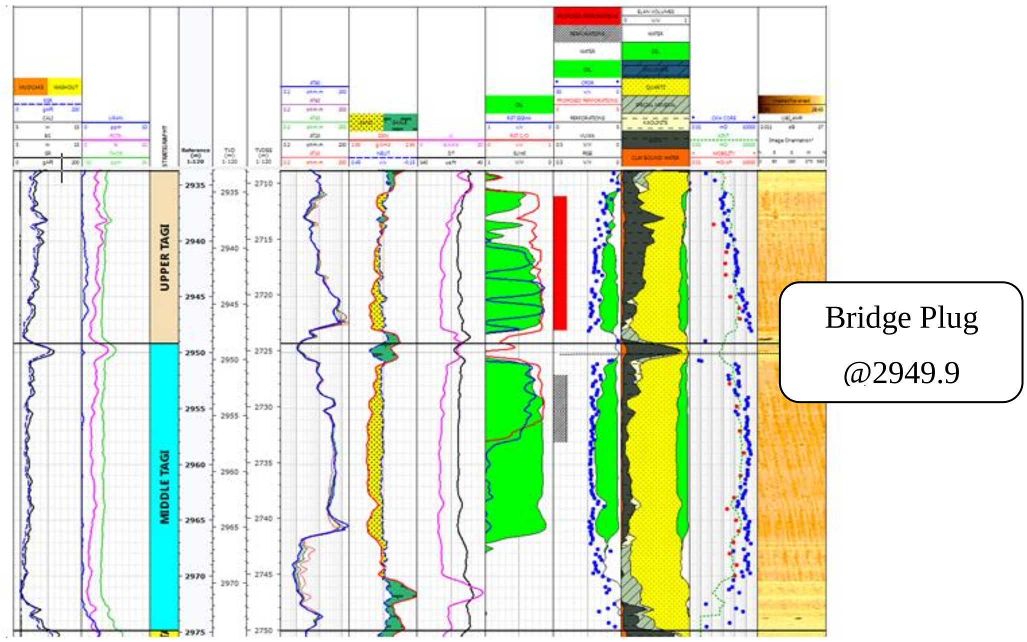


Figure III.11 WIRELINE log to set bridge Plug (12)

After 3 months from the perfs isolations the well struggle again due to high water cut and to recover the well productivity frequent cleanout & Gas lift jobs with Coiled tubing were done

- 20th September 2017, well ceased flowing
- On 24 & 28 September 2017 Gas lift operations done, the results were negative. [12]

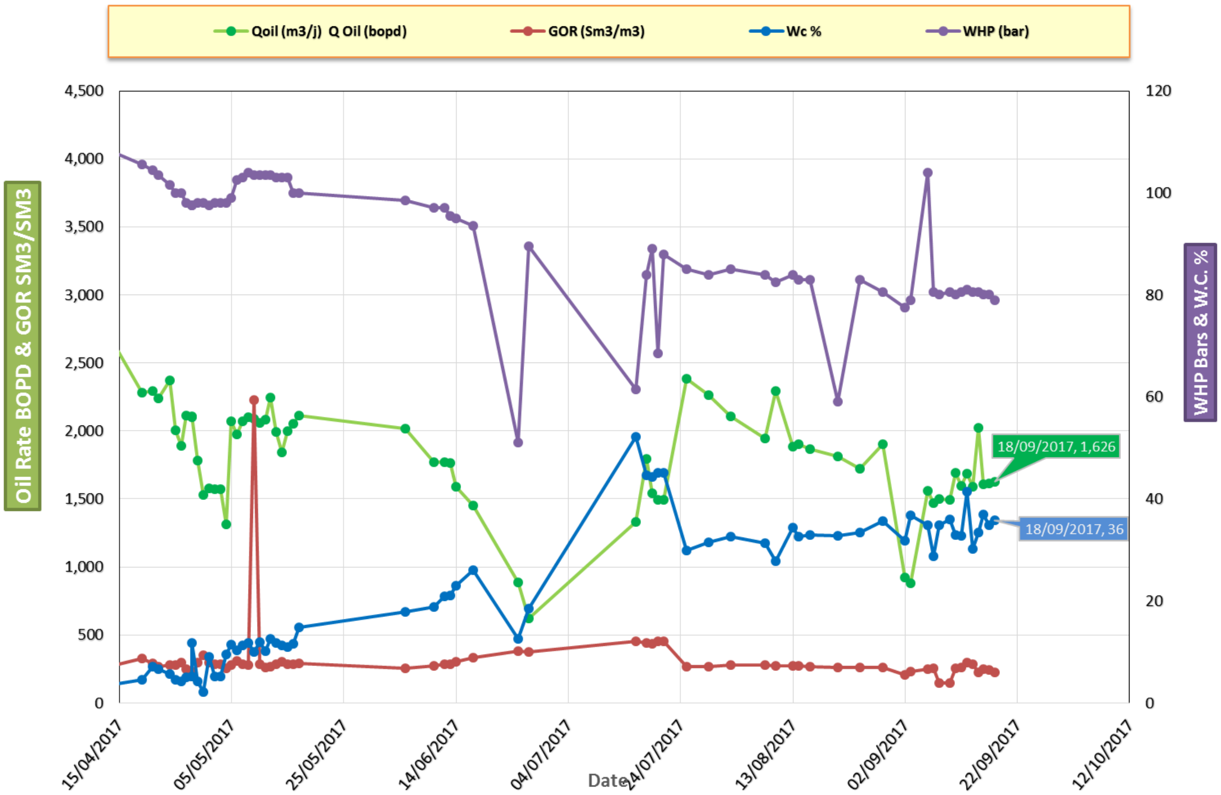


Figure III.12- SFNE 13 on MPFM test(12)

III.6 Naturel flow Modeling

For naturel flowing a model of SFNE 13 on PROSPER has been made. Once a model of the system has been calibrated to the actual data measured on the well, PROSPER can be used with confidence to model the well in different scenarios and make advanced predictions of well and reservoir data.

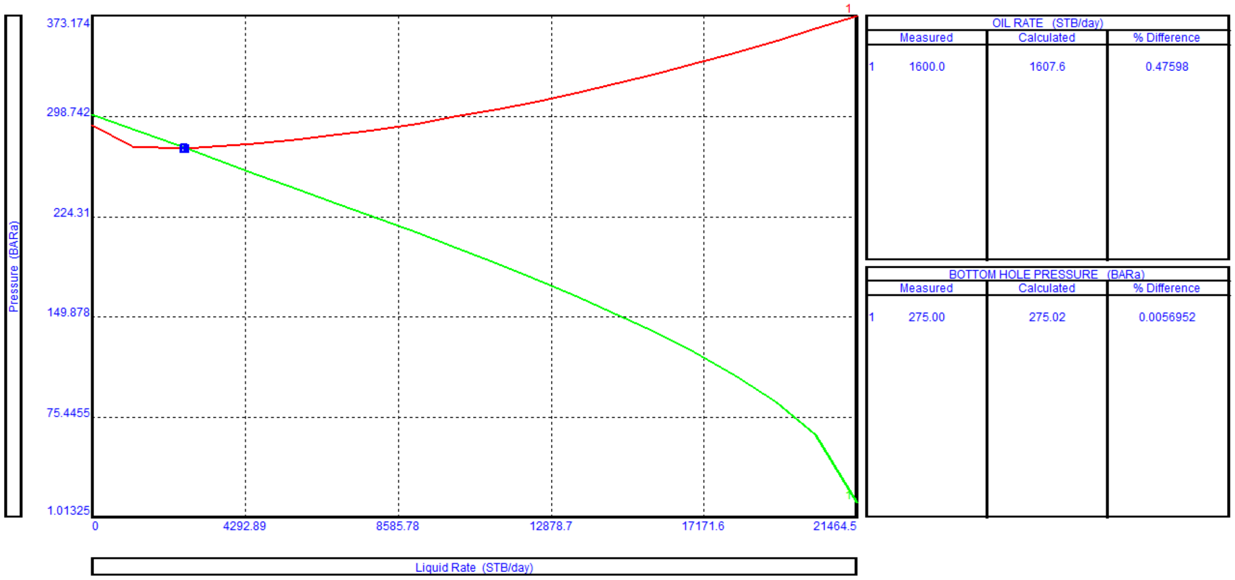


Figure III.13 the last naturally flowing System plot (Q= 1600 BOD and WC=36%)

The sensitivity of water cut on the well performance model shows that the well will cease flowing naturally after a WC = 50% ,we can see the outflow curve (VLP) moving upward away from the inflow curve (IPR) and no intersection between them after WC =50%

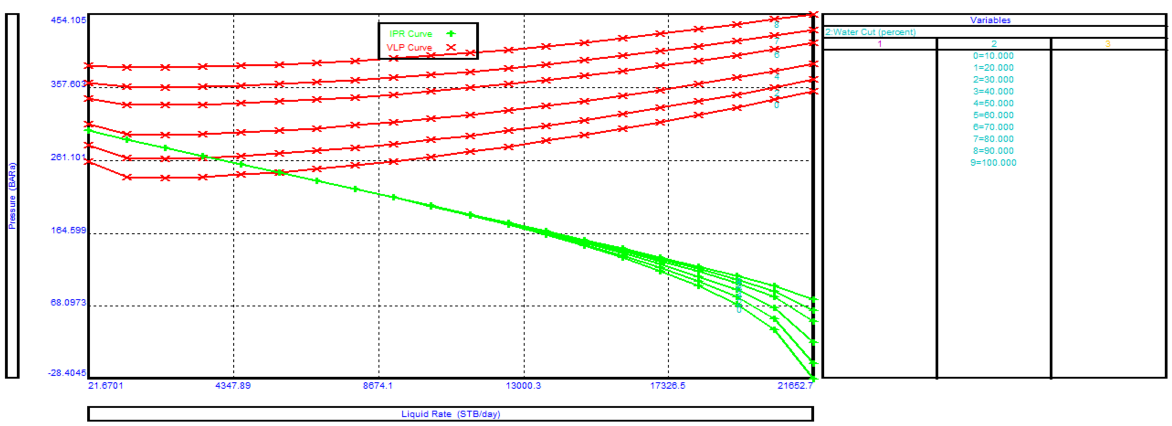


Figure III.14 Water cut sensitivity

Even if we open the chock to allow the well to flow at lower well head pressure we still governed by the flow line pressure so the minimum WHP the well flow though it is 70 bar

The sensitivity of WC according to this pressure showed that the well will not flow after 60%

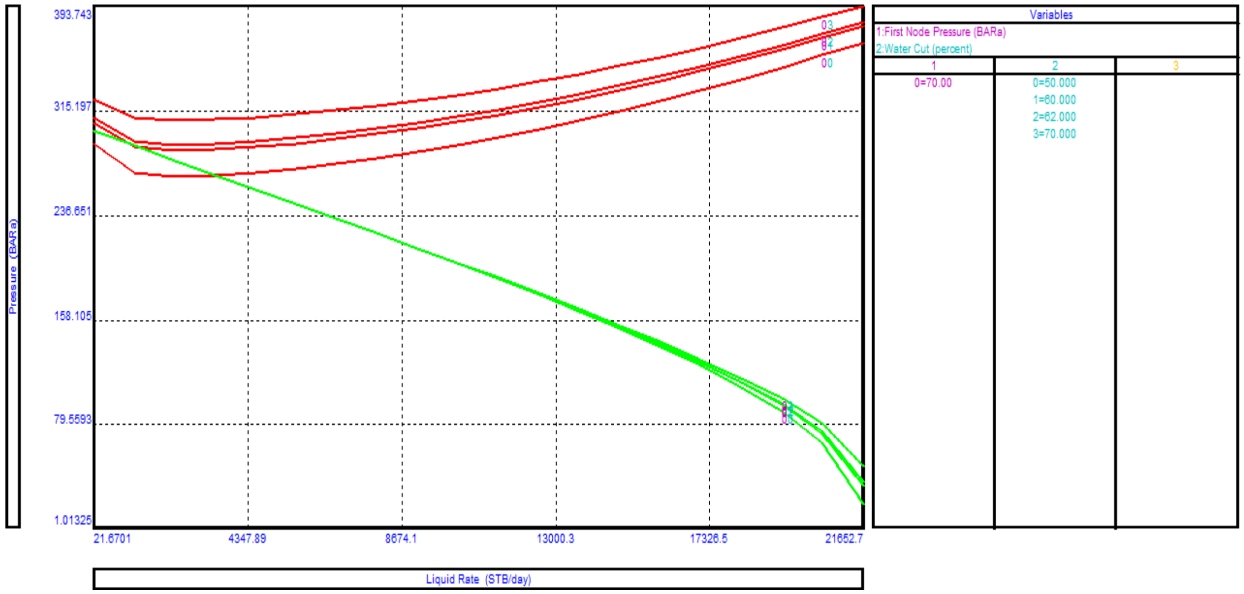


Figure III.15 WC sensitivity VS WHP=70 Bar

III.7 Artificial lift modeling (ESP well):

First we collect the well information and provide them to Contractor Company in this case is BAKER

The target liquid flow rate QL=800 Sm^3/d

WHP= from 100 to 150 bar

Operating frequency =50 Hz

Table III-3: Well information

	PARAMETER		UNITS
WELL INFORMATION	Casing information	9 5/8" x 47#, 0- 2000 m | 7" X 29#, 2000 - 3828m	OD, #/m
	Tubing information / Pump Depth	3 1/2" X 9.2#, 0-2350 m	OD, #/m
	Bubble Point Pressure, Limit Factor	**232.0**	**Bar**
	Top Perforations, Measured	2,936	m, MD
	IPR Method	PI	N/A
	Well PI	22	sm^3/d
	Target Q Operation @ Surface	**800**	**m3/d**
	Reservoir Temperature	88	C
	Water Cut	42 to 100	%
	Reservoir Static Pressure	299	Bar
	SG -Water	1.264	N/A
	GOR	260	sm3/m3
	SG oil	0.83	Ref to H_20

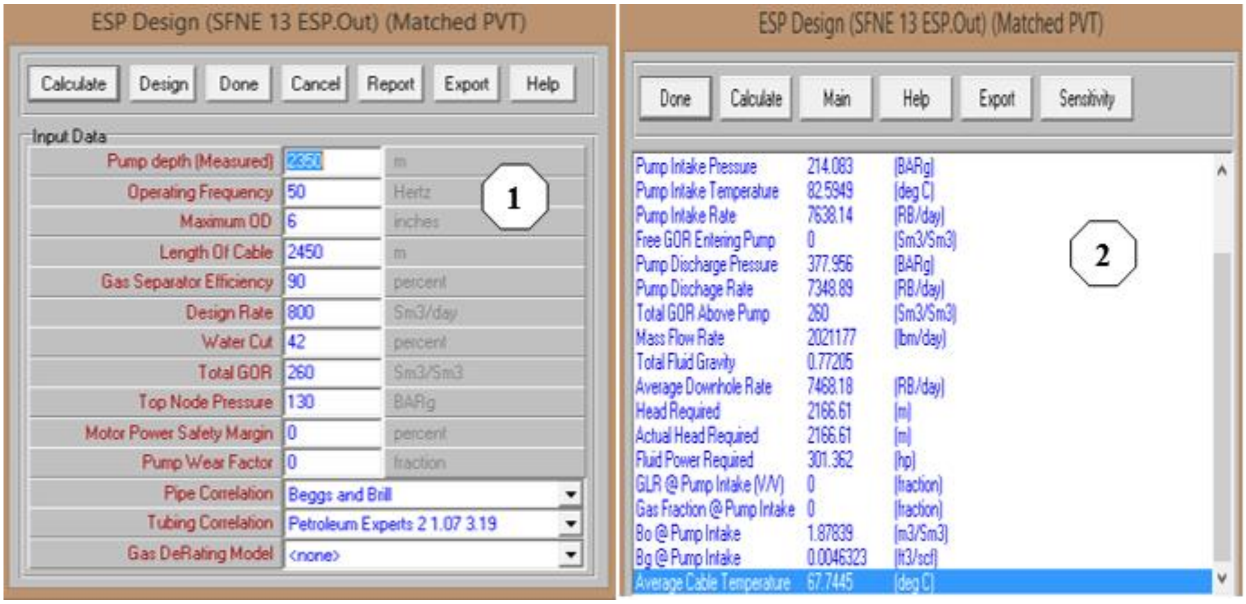


Figure III.16 ESP Desing output

- Using the information from the table, we can construct the ESP design model
- After calculation prosper will provide us the design results

We can use those calculations to identify if there is a need for gas separator by sensitivity button, if the point lay in the down side of Dunbar factor line then we must use gas separator. And if the contrary that's mean there is no need for gas separation like our case

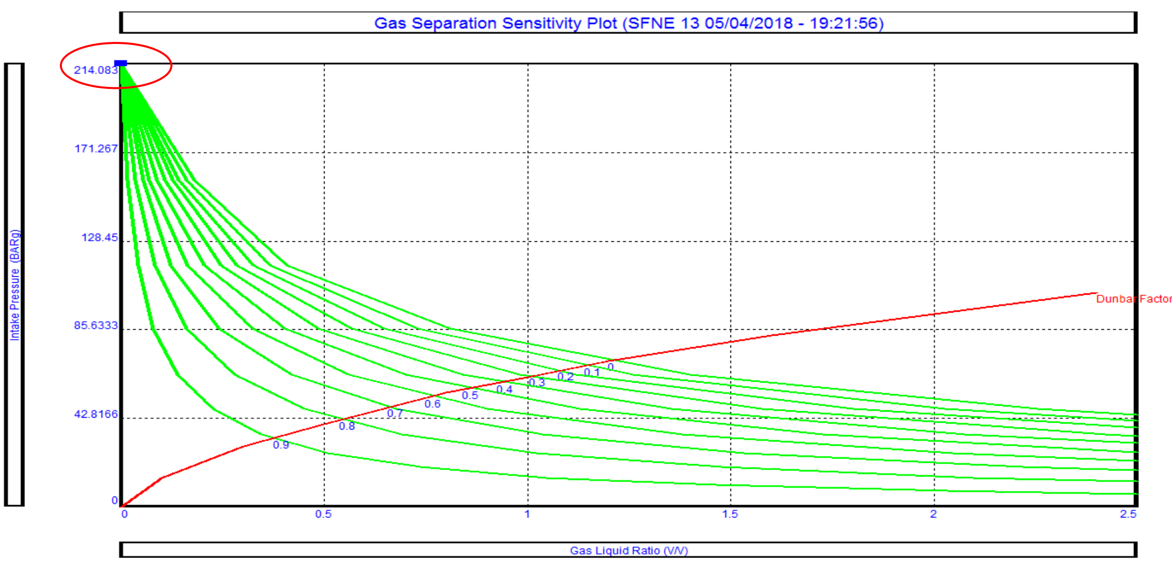


Figure III.17 gas separation selection

III.7.1 *Pump selection*

Prosper will short list the pumps that can provide the target flow rate in their Recommended Operating Range (ROR), and because the contractor is BAKER company we will choose from Centrilift pumps, we picked R5600 pump with 204 Stage

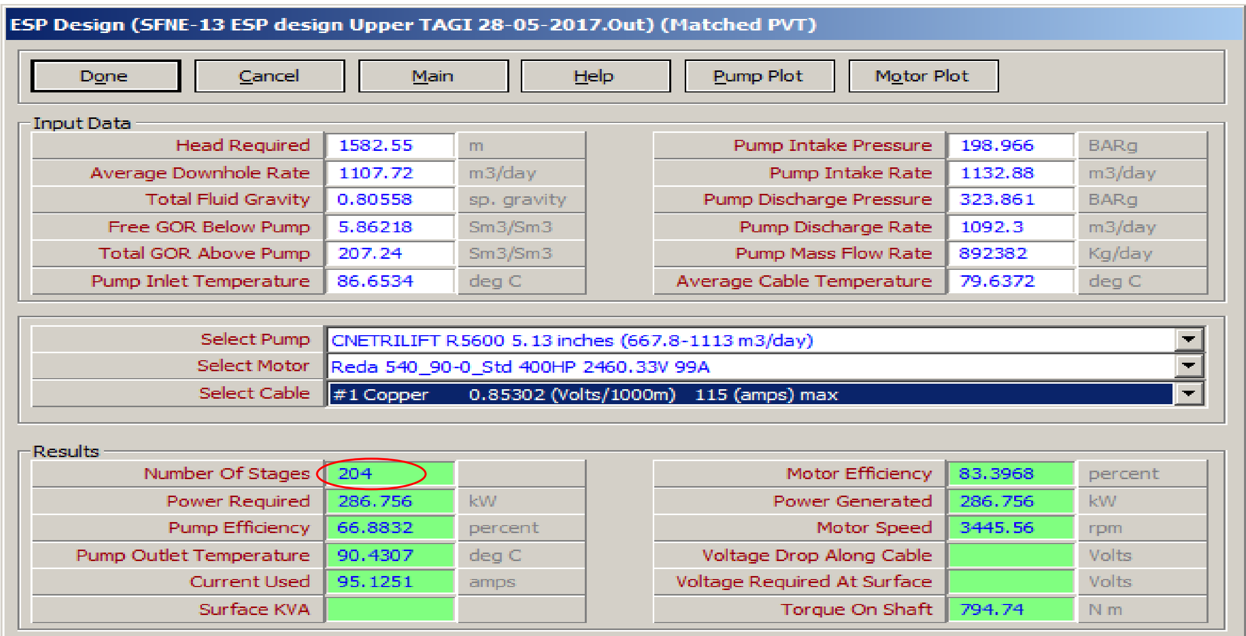


Figure III.18 ESP selection from Prosper

III.7.2 *SFNE-13 ESP Commissioning*

ESP workover Installation started on 29/10/2017 and finished on 15/11/2017

ESP commissioning (clean up) started on 15/11 @ 10 AM and finished @ 17 (7 hrs.)

At the end of commissioning phase, well parameters as follow:

- WHP = 38.7 Bars
- PIP = 192.72 Bars
- PD = 222 Bars
- W.C. = 45 %
- Water dilution 13 L/M

Using real data to match the ESP model

- QL = 892 Sm3/D
- W.C = 48 %
- PS = 298 Bars (ESP static readings)

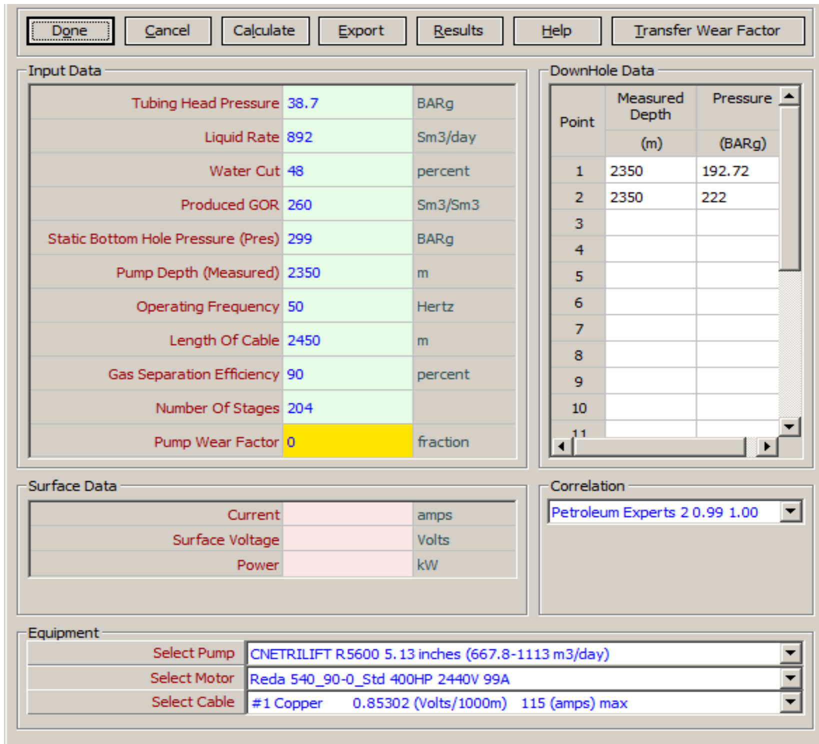


Figure III.19 Startup simulation on Prosper

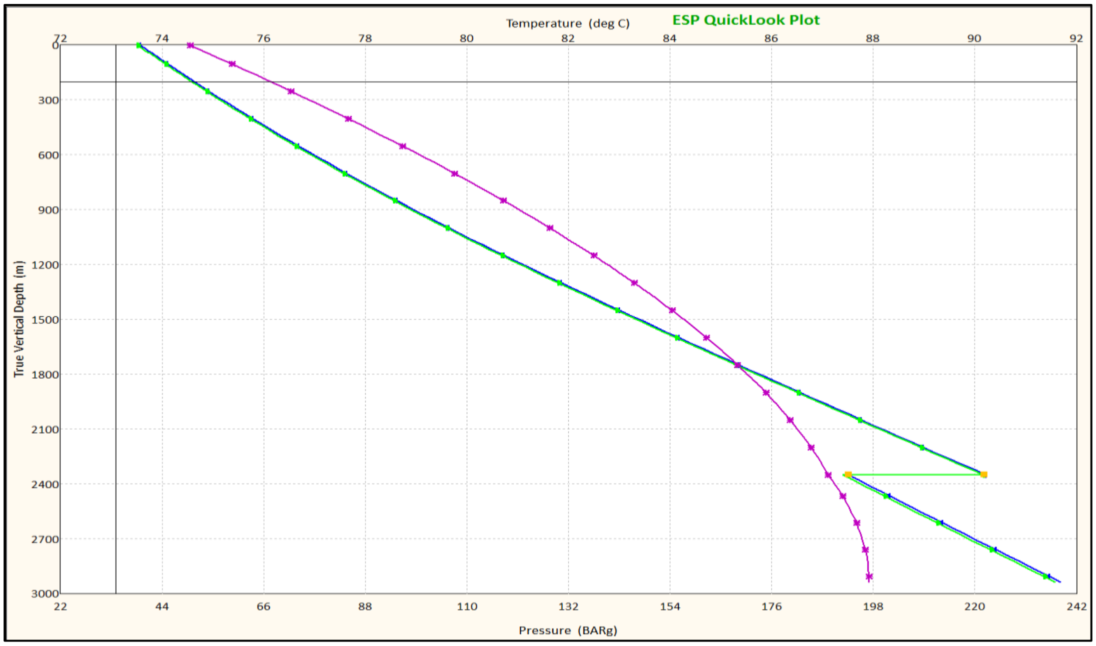


Figure III.20 ESP Pressure profile matching during workover

III.7.3 *ESP performance evaluation*

ESP was finally started on 08/12, ESP has been running continuously since 13/12/2017 at 18:30, with quite stable parameters, on 15/12/2017, a production test through Halliburton MPFM was recorded with following results:

Table III-4 Well test report(12)

Well Head			Oil			Water			Fractions		GOR
Choke	Pres	Temp	Std cond		SG	Std cond	Salinity	Water inj	GVF	WC	GORT
/64"	barg	deg C	Sbbl/d	Sm³/d	API	Sm³/d	g/l	l/mn	%	%	Sm3 / Sm3
N/A	**126.19**	**63.3**	**2458.77**	**390.90**	**38.6**	**220.60**	**300.0**	**15.0**	**51.71**	**33.72**	**191.15**

During test recording production parameters were quite stable, and ESP main parameters:

- PIP = 216.5 bar
- DP = 301 bar
- Operating Frequency = 50

ESP operating point is inside the ROR envelope

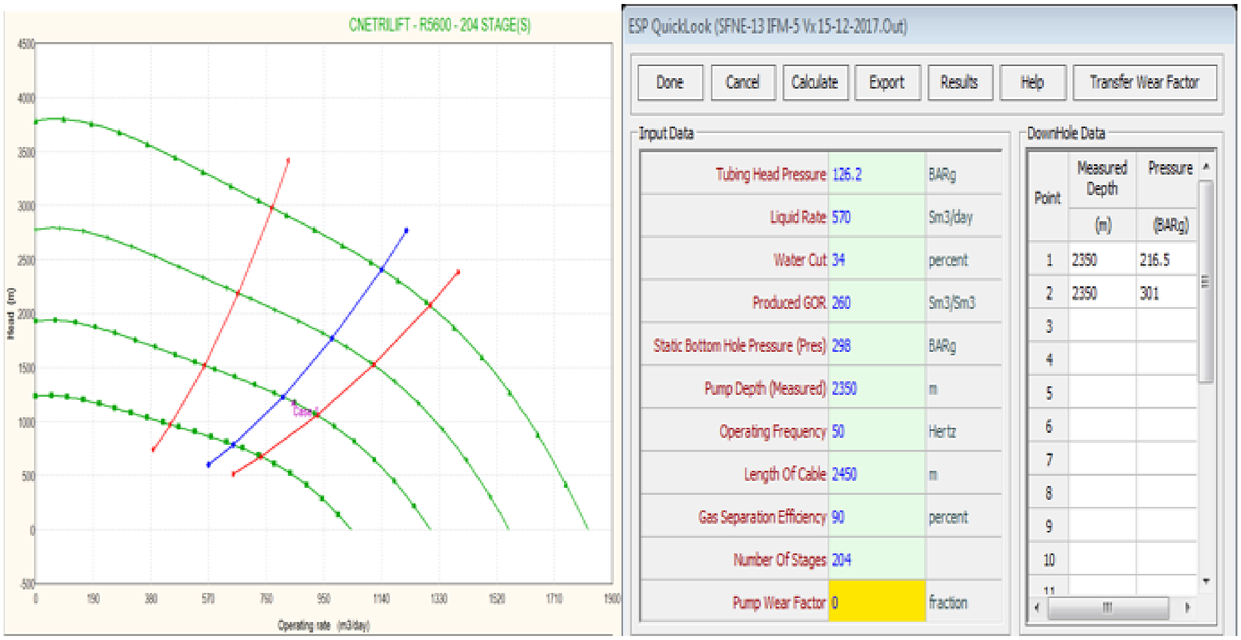


Figure III.21 SFNE-13 ESP performance curve

Using the well test data and the downhole gauge of the ESP we simulate the real performance on the well model ,we can see the operating point of the pump is inside the ROR near the BEP line .

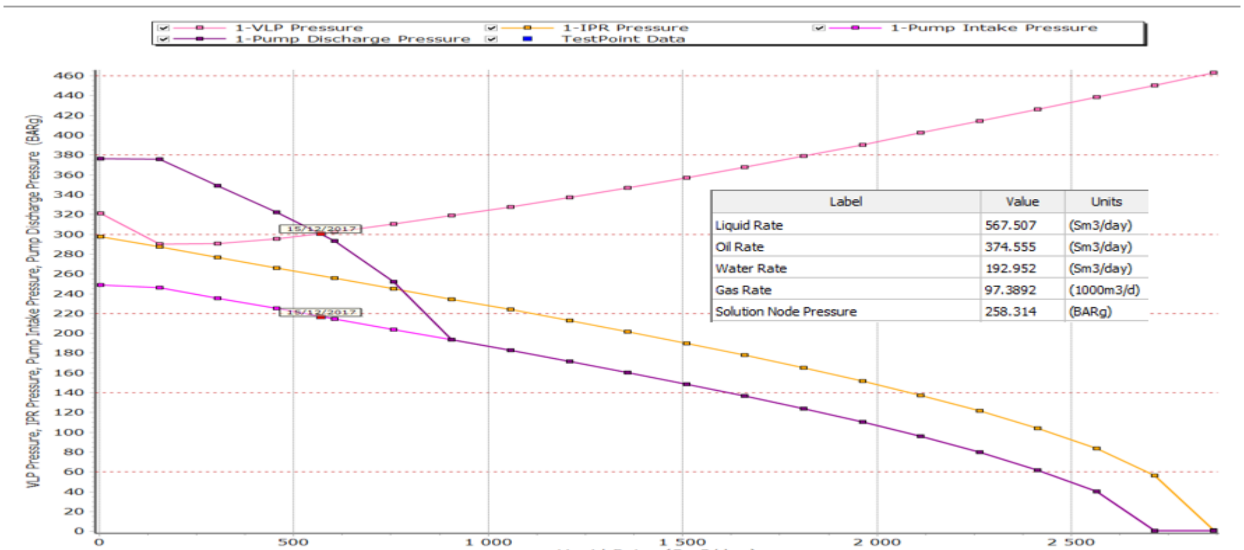


Figure III.22 VLIP-IPR matching using well test results

III.8 Expenses VS profites

Table III-5 Cost Vs income

ESP installation cost	55 K $
Surface equipment	100 K $
Daily rental	1 K $
Work over cost	2 M $
Total Cost	2.156

Daily Production	**2500**	**BOPD**
Barrel price	**60**	**$**
Total income	**150 000**	**$/D**

From the well daily production, it's obvious that the total cost of ESP installation and the workover can be covered within just 15 days

III.9 Recommendations

- ✓ Keep operating the ESP at the current conditions, if the well parameters changed by time try to operate the pump inside ROR envelope by playing on the choke size or Operating Frequency
- ✓ Collect fluid sample to verify WC value evolution
- ✓ Closely monitor the reservoir pressure trend on SFNE-7 (Abandoned spy well)
- ✓ Closely monitor dilution performance (90% of ESP shut down on BRN field caused by salt deposition)
- ✓ Continue performance monitoring through IFM-5 Vx tests and periodical MPFM (double check)
- ✓ Perform a bull heading to restore PI if the dilution line can't dissolve the salt

III.10 **Problems associated to ESP wells on BRN field**

GSA fields are characterized by a very challenging environment for Downhole completion materials:

- ✓ Presence of CO_2 in restricted reservoir area
- ✓ Aerated dilution waters and increase of oxygen content downhole
- ✓ High salinity up to 320 [g/l] and the related halite deposition problem
- ✓ High operations frequency due to salt obstruction in the string
- ✓ Service waters with solids and scaling problems, mainly carbonates and gypsum
- ✓ Bacteria in water producer wells

III.10.1 ***Crack of production tubing***

Several corrosion phenomena were noticed in the tubing especially on ESP wells and dedicated studies were carried out to identify the root causes of the failures and corrective actions.

III.10.1.1 ***Failure analysis***

An analysis of the failure occured in BRN production tubings since 2014 to May 2017 was performed; in particular it focus on the comparison between material, salinity and type of leakage was done in order to understand why leakagy occurs

Table III-6 Statistics about TBG failures (12)

N	Well	Failure date	Days in serv.	Mat.	Salinity NaCl (g/l)	Dist. from pin (m)	Notes
1	BRSW-16 ESP+D	Feb. 2014	N.D.	S13Cr	304	0.6	Longit. crack
2	BRSW-16 ESP+D	Feb. 2014	N.D.	S13Cr	304	1.1	Longit. crack
3	BRW-8 ESP+D	Jun. 2014	375	S13Cr	N.D.	0.5	Longit. crack
4	BRW-8 ESP+D	Jun. 2014	375	S13Cr	N.D.	0.9	Longit. crack
5	BRW-1 ESP+D	Aug. 2014	525	S13Cr	N.D.	0.3	Longit. crack
6	SFNE-8 ESP+D	08/12/15	N.D.	S13Cr	N.D.	N.D.	Trans. crack
7	BRW-13 ESP+D	04/12/15	252	S13Cr	223	N.D.	Tubing leak
8	BRW-8 ESP+D	09/01/16	184	S13Cr	320/330	N.D.	Tubing leak
9	BRW-13 ESP+D	01/03/16	N.D.	S13Cr	223	N.D.	Tubing leak
10	BRSW-10 ESP+D	Oct. 2016	823	CS	N.D.	0.2	hole
11	BRSE-1 ESP	25/12/16	716	CS	302	N.D.	Tubing leak
12	BRSW-10 ESP+D	20/02/17	100	S13Cr	120	N.D.	Tubing leak
13	BRW-ESW-1 ESP+D	20/02/17	322	S13Cr	168	0.7	Longit. crack
14	SFNE-8 NF+D	25/04/17	415	S13Cr	173	N.D.	Tbg parted
15	SFNE-8 NF+D	25/04/17	415	S13Cr	173	N.A.	Mule shoe Longit. crack
16	BRW-1 ESP+D	15/05/17	68	S13Cr	320	0.6	Tubing leak Longit crack
17	ROMN-3 ESP+D	16/05/17	130	S13Cr	270	0.8	Tubing leak
18	BRSW-21 NF	2016	N.D.	CS	N.D.	N.A.	
19	SF-5 NF	05/09/17	1835	CS	N.D.	N.D.	

We can samurais the above table on two types of tubing material:

- ✓ CS: Carbon steel TBG
- ✓ S13Cr: Super 13 chromium steel (have about 12 to 14% chromium)

ESP and **NF** wells (naturel flow),

+D: dilution injection

Table III-7- Samurais of statistics (12)

Material	Type of Well	N of failures
S13Cr	ESP + Dilution	13
	NF + Dilution	2
Carbon Steel	ESP + Dilution	1
	ESP	1
	NF	2
Total		**19**

From this table we can see that around 90% of failures on ESP wells come from the completion using S13Cr tubing

- **Carbon Steel Failures:** The most probable cause of well failures:

- External corrosion probably due to CO2, low water pH and high salinity

- **S13Cr Failures**: The most probable cause of well failures:
  - Chloride Stress Corrosion Cracking, enhanced by Oxygen, which is always present in the failed wells
  - High stress and/or vibrations caused by ESP pump.

III.10.1.2 *Recommendations for TBG Material Selection*

Main factors affecting the performance of tubing materials: Stress, oxygen, salinity

Table III-8 Material Selection (12)

Well Type	Stress	Oxygen	Salinity NaCl	1st Option
NF	Low	No	< 200 g/l	S13Cr
			> 200 g/l	CS
NF + Dil.	Low	O_2 < 50 ppb	< 200 g/l	S13Cr
			> 200 g/l	CS
		O_2 > 50 ppb	All	GRE
ESP	High	No	All	CS
ESP + Dil.	High	O_2 < 50 ppb	All	CS
		O_2 > 50 ppb	All	GRE

III.10.2 *Dilution system for ESP wells*

Due to high salinity in all GSA reservoirs, the ESP wells provided by injection line till the bottom of the pump (intake). The installation of pipe below the ESP is the technical solution adopted by GSA to assure the dilution of salty water in front of perfs especially for the TAGI producers (TAGI water Salinity 200000-300000 ppm).

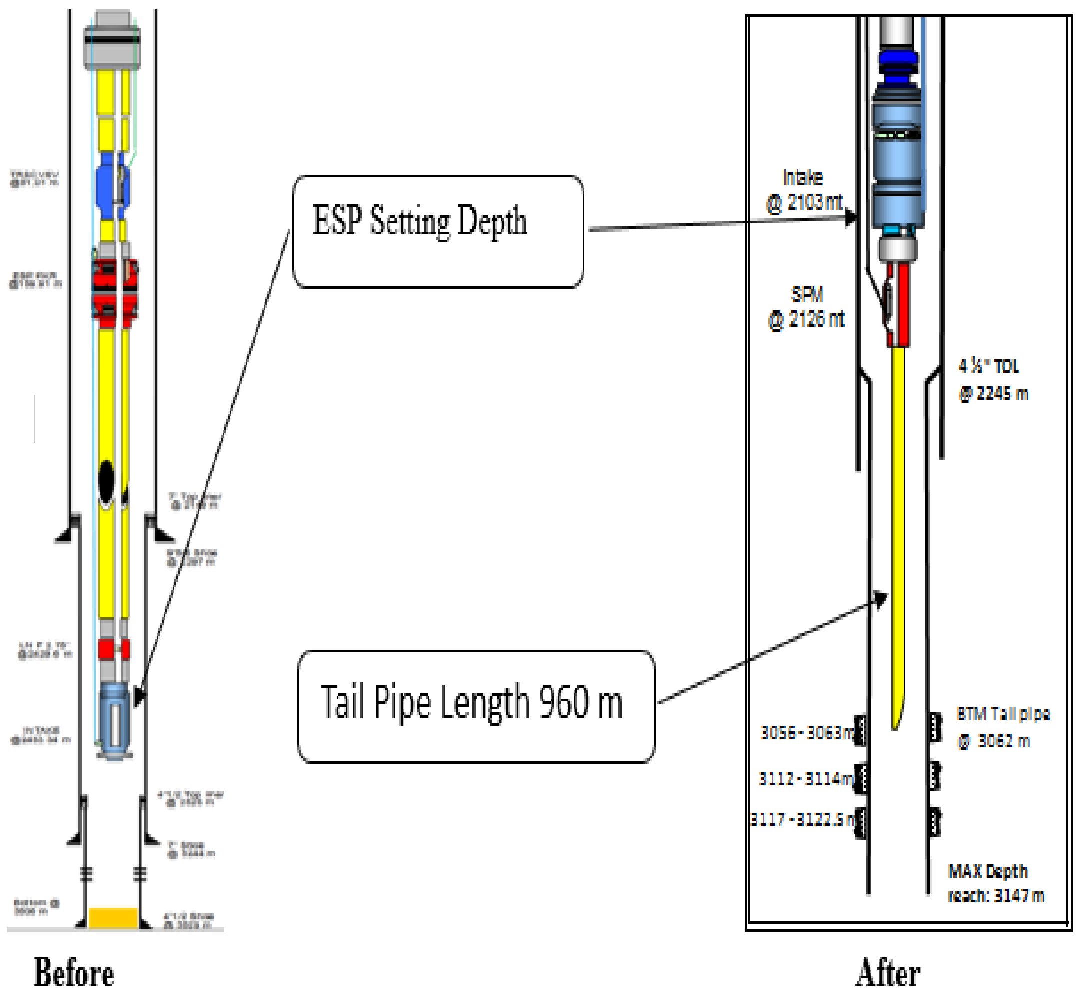


Figure III.23 ESP tail pipe

III.11 Summary and Conclusion

- On 07/07/2016 SFNE-13 restarted after long time of shut-in, WC has been increasing gradually from 28% to 44%;
- On 26/08/2016, Upper TAGI perfs extension were done (2936 – 2948 m) and WC decreased to 27% due to anhydrous oil coming from Upper TAGI level (PLT October 2016);
- Since February 2017, well performance has been worsening due to increase in water production. Several cleanout jobs were done;
- On 05/04/2017 Copperhead 4 ½" bridge plug was set @ 2949.4 m to isolate Middle TAGI. Production test of 08/04 revealed oil production 2500 Sbopd and WC = 8% (vs. 40% pre-isolation). Subsequently, WC continued to increase with consequent salt issues and CT jobs.
- On 20/09/2017 the well quit flowing. Following gas lift attempts were negative and the well was shut-in waiting for workover;
- Workover for ESP (Baker R5600 204 = 3 x 68 stages + tandem gas separator) finished on 15/11/2017 with ESP commissioning.
- ESP start-up on 08/12. Several shutdown occurred on , from 13/12/2017 the ESP has been running continuously with quite stable parameters.
- The ESP is operating inside the Recommended Operating range, near the best efficiency line
- Since ESP installation, no CT intervention has been done on the well.
- The MPFM test shows that Q_o=2500 SBOPD that's mean a gain of 60% from last naturel flowing rate (1600 SBOPD).

We can see the benefits of using ESP system from reducing the cost of oil production by minimizing the well intervention operations and maximizing oil recovery

CONCLUSION

CONCLUSION

In Algeria, BRN filed is the haven of artificial lift. The installation of ESP pumps started since 13 years ago, and in this year, the engineering department has completed the first well with sucker rod pump and the , more than 5 other wells will be completed in the next year.

With the gas lift on BRW field and the PCP pumps on RAR field and with daily lifting operation with two Coil Tubing unites using nitrogen all this make BRN the unique field in Algeria with such artificial lift aspects

As we have seen the ESP give us a gain of 60% of oil rate from just one well (SFNE 13), and with its flexibility and ability to handle WC till 100% and it's suitability to vertical or horizontal wells will make it the first artificial lift method in the oil field in the next few years.

The negative points of ESP system is the relatively short run life and the cost of workover in case of failure, the manufactures searching for alternatives to deploy the ESP system such as CT, wireline or even small unites of workover to overcome the high rate of rigs, with the advance in technology and electronic protection systems the ESP life time will exceed the world average (2 years) and made it the most cost effective artificial lift method

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APPENDIX

COMPLETION SKETCH

Groupment Sonatrach/Agip

DATE:	15/Nov/17	ARPO 20 / C	
FIELD NAME	Sif Fatima North East	WELL NAME	SFNE - 13
Account	578513		

SINGLE COMPLETION ■ VERTICAL ■ DEVIATED ☐ HORIZONTAL ☐ SELECTIVE ☐ ESP ☐

ICGP ☐ OHGP ☐ GRAVEL SIZE: 20/40 ☐ 40/60 ☐

String weight up	43 [t]	Slotted Liner Casing Size: ____ [in]	Type of packer fluid: NaCl Brine
String weight down	44 [t]	Top: ____ [m] Bottom: ____ [m]	Density: 1,15 kg/lt
Make up report	• yes [y/n]	Well deviation [max.] 3 degrees	

GENERAL INFORMATIONS	
DRILLING PERIOD	September /October 2008
RIG USED	Saipem 5832
RT/TIE DOWN	9.43
WELL HEAD RATING	10 K psi - Working Pressure
TOTAL DEPTH	3065 m MD RKB
TOP CMT PLUG	
BP RETAINER	2049.4
ANNULUS FLUID	1.15 Kg/l NaCl Brine
BTM CHECKED ON	2044 m on 05-11-2017
GEOG COORD LAT	31° 02' 21,38" N
GEOG COORD LONG	08° 29' 22,13" E

WELL HEAD	DESCRIPTION
XMAS TREE	4 1/16" x 4 1/16" x 2 1/16" 5 K psi
TUBING SPOOL	11" 10K x 13" 5/8 10K psi
BACK PRESSURE VALVE	2.875" RPT (installed)
TUBING HANGER	ESP TC-8-ECC 13 1/2" x 4.25" 4NA-2G-LH top thread
ADAPTER	13 5/8" 10K Speedlock x 4 1/16" 5K FLG
Wellhead	18 5/8" 5k" 13 5/8" 5k " 13 5/8" 10k

PRODUCTION CASING

Nom OD	Thd	lb/ft	S. Grade	Top (m)	Bottom (m)
9 5/8"	HSC	47	P 110	10.76	2233
7"	AMS	29	P 110	2041.44	2804
4"½	V. TOP	12.6	P 110	2394.3	3052

CSG/LIN OD	18 5/8"	13 3/8"	9 5/8"	7"	4,5"
TOP AT m	10.85	11.06	10.76	2041.44	2394.3
SHOE AT m	88	396	2233	2804	3052
CMT UP m	SURF.	SURF.	SURF.	2041	2394

■ LINER HANGER : 7" TOP @ 2041,44

■ LINER HANGER : 4½" TOP @ 2394,30 m

☐ LINER HANGER :

CASINGS CHARACTERISTICS

OD NOM	TO m	STEEL	THRD	lb/ft	ID mm
18 5/8"	88	K55	TEN. ER	96.5	448.4
13 3/8"	396	J55	TEN. ER	54.5	320.4
9 5/8"	2233	P 110	HSC	47	220.5
7"	2804	P 110	AMS	29	157.1
4 1/2"	3052	S13Cr	V. TOP	12.6	100.5

Production interval /I perforated zone:

Top (mMD)	Bottom (mMD)	Level
2,936	2,948	Upper TAGI

TYPE OF GUNS :	2 7/8" HSD
TYPE OF CHARGE :	Power Jet Nova
SHOOT DENSITY :	6 spf

Isolated perforations

Top (m)	Bottom (m)	Level
2,952	2,958	Middle TAGI

NOTES :

TRSSV (Start open press @ 1200 psi, Full open press @ 1300 psi; close press @ 900 psi. Oil return @ 5000 psi: 33 ml

AGV (Start open @ 1400 psi, Full open @1800 psi; Start Close @ 1300 psi; Full Close @ 900 psi. MAX CL Press: 5000 psi

Apply 2000 psi in annulus to shear and lock open

Packer

Nom. O.D.	Manufact.	Model type	I.D.	Depth
9 5/8"	Schlumberger	Hydraulic Set	2.934"	163.08 (MCE)

Cut Zone	From Top Of Nipple (2.74m -2.55m) 18.5 Cm
Shear Release	71400 lbs
SIZE	8.3" ESP 47 / 53.5#
TYPE	Schlumberger Hydraulic Set Retrievable ESP Multiport Packer

COMPLETION STRING

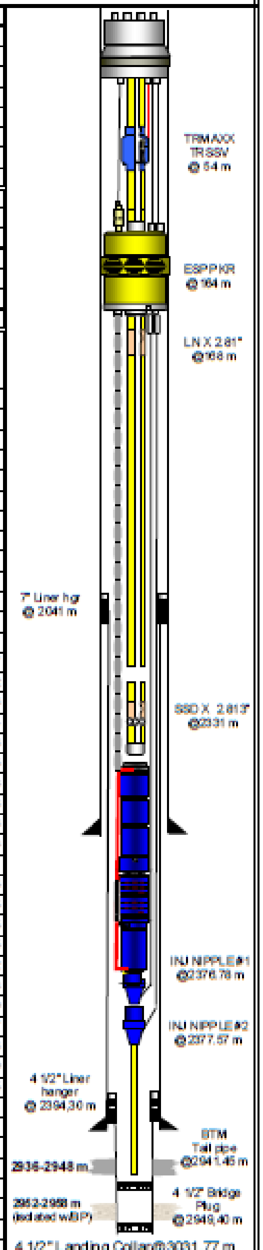
Tubing

Nom. O.D.	Thread	lb/ft	Steel Gr.	%	Down to
3"1/2	HSC	9.2#	P110	0	2331.62
1.66"	API NU	2.33#	S13CR95	0	2941.45

MAKE UP TORQUE : 4270 ft/lb GREASE : Weatherford Lube Seal

REF	COMPLETION ASSEMBLY	ID	OD	DEPTH
A	Tubing hanger TC-8-ECC Type 13 1/2" NOM OD x 4.25" 4NA-2G-LH top thread x 3 1/2" VAM TOP btm thread w/ 2.875" BPV Halliburton RPT type W 4 control line port (2 port 1/4" LP + 2 port 3/8" LP) + penetrator RMS	2.970"	13.52"	9.43
B	Pup Joint 3 1/2" 9.2# 95KSI, Vam Top Pin x Pin	2.867"	3.500"	9.66
C	X-Over Pup Joint 3 1/2" 9.2# P110 Vam Top Box x HSC Pin	2.942"	3.500"	10.97
	4 x 3 1/2" 9.2# P110 HSC Tubing Joints	2.992"	3.500"	11.99
D	X-Over Pup Joint 3 1/2" 9.2# P110 Vam Top Pin x HSC Box	2.980"	3.500"	50.47
E	SCSSV TRM AXX-5E 3 1/2" 2.812" X-Type, Vam Top BxP	2.812"	5.161"	53.98
F	X-Over Pup Joint 3 1/2" 9.2# P110 Vam Top Box x HSC Pin	2.942"	3.500"	55.25
	11 x 3 1/2" 9.2# P110 HSC Tubing Joints	2.992"	3.500"	56.99
G	X-Over Pup Joint 3 1/2" 9.2# P110 Vam Top Pin x HSC Box	2.980"	3.500"	162.73
H	SLB 9 5/8" ESP Packer 9.2# S13Cr 110 Ksi Vam Top	2.934"	8.322"	164.78
I	Pup Joint 3 1/2" 9.2# 95KSI, Vam Top Pin x Vam Top Box	2.867"	3.500"	166.50
L	2.813" "X" L. N. 3 1/2" 9.2# S13Cr 95ksi Vam Top B x P	2.813"	3.97"	168.51
M	X-Over Pup Joint 3 1/2" 9.2# P110 Vam Top Pin x HSC Box	2.986"	3.500"	168.80
	227 x 3 1/2" 9.2# P110 HSC Tubing Joints	2.992"	3.500"	171.77
N	X-Over Pup Joint 3 1/2" 9.2# P110 Vam Top Pin x HSC Box	2.867"	3.500"	2,328.77
O	SSD 3 1/2" 9.2# 110Ksi Vam Top B x P 2.81" X Profil	2.813"	4.281"	2,331.62
P	X-Over Pup Joint 3 1/2" 9.2# P110 Vam Top Box x HSC Pin	2.980"	3.500"	2,332.66
Q	X-Over 3-1/2" 9.2# HSC Box x 3-1/2" 9.3# EUE Pin	2.996"	3.900"	2,334.64
ESP	DISCHARGE HEAD B/O PMP 513 3.5 EUE 416SS	-	4.007"	2,334.98
ESP	PORTED HEAD (Welllift DGU)	-	5.130"	2,335.15
ESP	PUMP 500S RG FL-MT RG5600-68	-	5.130"	2,335.38
ESP	PUMP 500S RG FL-MT RG5600-68	-	5.130"	2,342.03
ESP	PUMP 500S RG FL-MT RG5600-68	-	5.130"	2,348.68
ESP	INTAKE GAS SEPARATOR 513 GSRXFER UT N AR	-	5.130"	2,355.33
ESP	INTAKE GAS SEPARATOR 513 GSRXFER LT N AR	-	5.130"	2,356.31
ESP	SEAL GSB3DB XUT H6 FER SSCV AB/AB PFS	-	5.130"	2,357.45
ESP	SEAL GSB3DB XLT H6 FER SSCV AB/AB PFSA	-	5.130"	2,359.55
ESP	MOTOR 450 XP UPPER TANDEM 142HP/1175V/77A/50Hz	-	4.500"	2,361.65
ESP	MOTOR 450 XP LOWER TANDEM 142HP/1175V/77A/50Hz	-	4.500"	2,368.95
ESP	WELL LIFT H ASM 5000PSI MGU	-	4.500"	2,376.22
R	SLB Chemical Injection Mandrel 2 3/8" EUE Pin x Pin	1.950"	4"	2,376.78
S	XO 2 3/8" EUE Box x 2 3/8" EUE Box	3.100"	2.375"	2,377.39
T	SLB Chemical Injection Mandrel 2 3/8" EUE Pin x Pin	1.950"	4"	2,377.57
U	XO 2 3/8" EUE Box x 1.66 NU Pin	3.000"	2.375"	2,378.18
	57 x 1.66 NU 2.4# Tubing	1.380"	1.66"	2,378.39
	Bottom Tail Pipe Half mule shoe			2,941.45
	Note:			
	Installed 2 x Double injection check valve just below Packer			
	26/08/2016			
	Perforated Upper TAGI 2936-2948 mMD			
	05/04/2017			
	Set SLB 4 1/2" Copperhead Bridge Plug 10 kpsi (top 2949,4 mMD)			
	Isolated Middle TAGI 2952-2958 mMD			

WORKOVER	JOB PURPOSE
10/29/2017	ESP 1st installation



Rig Supervisors: Bonincontro F. / Guazzini V.

Superintendent / Completion Engineer: Rosa F. / Braconi M.

Figure 0.1 SFNE 13 Completion

Groupment Sonatrach / Agip

WELL SITUATION
(WELL HEAD)

DATE: 15-Nov-17	ARPO 20 / B	FIELD NAME	Sif Fatima North East
		WELL NAME	SFNE - 13
		Cost center	578513

NORMAL	
UNITIZED	■
SUB SEA	
HORIZONTAL	

Cellar Dimension		
Length:	5	[m]
Width:	3	[m]
Depth:	2	[m]

Well Head On Location		
Max Elevation:	2.63	[m]
From:	Ground Level	

Well Head Recovered	
Cut at	
From:	
Flange welded on:	

Component Type	Lower Connection Ø [in]	Lower Connection w.p. [psi]	Upper Connection Ø [in]	Upper Connection w.p. [psi]	Manufacturer
X-Mas tree Solid Block	4 1/16"	6650	4 1/16"	6650	FMC Composit Block
Lower M. Valve	4 1/16"	6650	4 1/16	6650	
Head Adapter	13 5/8"	10000	4 1/16"	6650	speedloc clamp
Tubing Spool					
Casing Spool					
Braden Head					

L. M. Valve: Manual Lower Master Valve 4 1/16" 6.65K

Tbg hanger Type: TC-B-ECC O.D.: 13 ½" I.D.: 2.875" Top Thread: 4.25 4NA-2G-LH

BPV Type: Halliburton RPT 2.875" (installed) O.D.: 2.875"

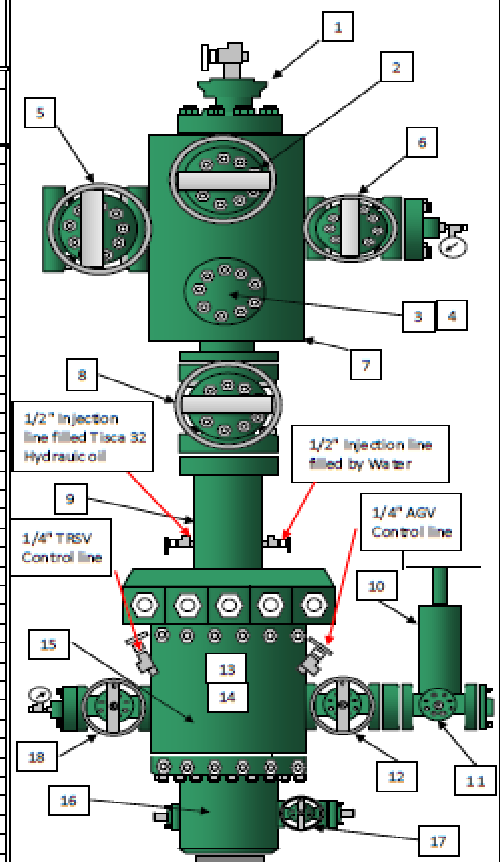
X-mas tree: Vert. I.D.: 4"1/16 Horiz. I.D.: [illegible] W.P.: 6.5K psi

Hanger seal		Actuator			
Metal seal		Pneumatic	☐	Oper. pressure (kg/cm^2)	
Elastomer:		Hydraulic	■	Max. pressure (kg/cm^2)	

Material description

Serial Number	ITEM	Description	Part number
05 05 261	1	Tree Cup 4 1/16" 6 1/2 ACME 1/2" NPT with needle valve	P200001416
09 05 261	2	Swab Valve 4 1/16" 5Kpsi	P400001523
90542	3	Upper Actuated Master Valve	P400001623
0810-43109-02	4	Upper MV Actuator 5000 psi working pressure	P100002548
09 04 143	5	Production Wing Valve 4 1/16" 5Kpsi	P151600
2008 12 1509	6	Kill Wing Valve 2 1/16" 5Kpsi	90 120 831
09 0614	7	X-Mass Tree Block 4 1/16" x 4 1/16 x 2 1/16" 5Kpsi	P200001472
09 04 138	8	Manual Lower Master Valve 4 1/16" 5Kpsi	P151607
09-05-210	9	Speed Lock adapter 13 5/8" 10K x 4 1/16" 5Kpsi	P200001458
1504-85400-10	10	AGV Actuator	P100002 1481
GU 15-06-41F	11	Actuated Gate Valve 2 1/16" 5Kpsi (AGV)	P000013487
NA	12	Manual gate valve 2 1/16" 10K	90130871
98-05-53	18	Manual gate valve 2 1/16" 10K	90130316
16390	19	Adapter Flange 2 1/16" 5k x 2 1/16" 10k	NA
	13	Packoff Assy 9 5/8" x 5000 PSI	P400001417
	14	Mandrel Hangers 9 5/8"	P400001416
	14	Mandrel Hangers 13 3/8"	P400001399
	15	TBG HEAD 13 5/8" 5K X 13 5/8 10K FLAMP TOP	P400001411
	16	CSG 15 1/4"ACME x 13 5/8 10K	P400001404
	17	CSG Outlet 2 1/16 5K	P100001836
		Landing Ring 18 5/8 SLIP ON	P400001396

WELL HEAD SKETCH



In case of dual completion, specify Long and Short string position on well head valves

Notes:

Tubing hanger FMC TC-B-ECC modified with Top Thread: 4.25 4NA-2G-LH

One of injection line displaced by Tisca 32 Hydraulic Oil

2.875" RPT BPV Installed on 15-November-2017

On 15-November-2017 Installed and tested 2 1/16" 5K AGV Gate Valve

Supervisor: Bonincontro Flavio / Guazzieri Vincenzo

Superintendent/Completion Engineer: Rosa Francesco / Braconi Maurizio

Figure 0.2 SFNE 13 WELL HEAD

GROUPEMENT SONATRACH-AGIP
DEPARTEMENT ENPR

Static Profile Of Pressure & Temperature

DATE: 16-Nov-2017

FIELD NAME: SFNE
WELL NAME: SFNE-07

SINGLE COMPLETION ☑	SELECTIVE ☐	VERTICAL ☑	HORIZONTAL ☐	SHORT STRING ☐	
DUAL COMPLETION ☐		DEVIATED ☐		LONG STRING ☐	

General Data

RKB Elevation @ m.	8.32	Base Flange ☐	Tbg Spool ☐		
Tubing Size OD	4 1/2	Weight [lb/ft]		m.	2342.39
Tubing Size OD		Weight [lb/ft]		m.	
Tubing Shoe Ø	4 1/2"			m.	2342.6
Packer data	BAKER SB 3			m.	2585.54
				m.	
Minimum I.D. String	LNRPT 3.75 @ 2304				
Annulus	/	CHP	0	[Kg/cm²]	

Interval Pérforé

De [m.R.T.]	à [m.R.T.]
2918.0	2927.0

Tbg Drifted with: Gauge Cutter — Size: 3" — To [m]: 2943 m/RT — Last Depth: S.B 2" @2943 m/RT

B.H. Sample:

Well Status

Static	☑	Q. GAS	[Sm³/j]
Dynamic	☐	Q. OIL	[m³/j]
Duse	☐	Q. WATER	[m³/j]

Time [HH:MM]	m/RT [m]	m/s.n.m. [m]	Temp. [°C]	Pres. [bar]	Gradient [bar/m]
10:17	0		35.02	0.99	
10:02	500		40.04	8.03	0.0141
9:51	1000		51.62	67.24	0.1184
9:41	1500		62.53	126.25	0.1180
9:31	2000		73.62	186.23	0.1200
9:19	2500		81.00	245.94	0.1194
9:09	2918		80.86	297.88	0.1243

Date of close :			
Depth Top Perfos	2918 m/RT		
SWHP =		0.99	bar
SBHP @ Depth Top Perfos 2918 m/RT		297.88	bar

Note :

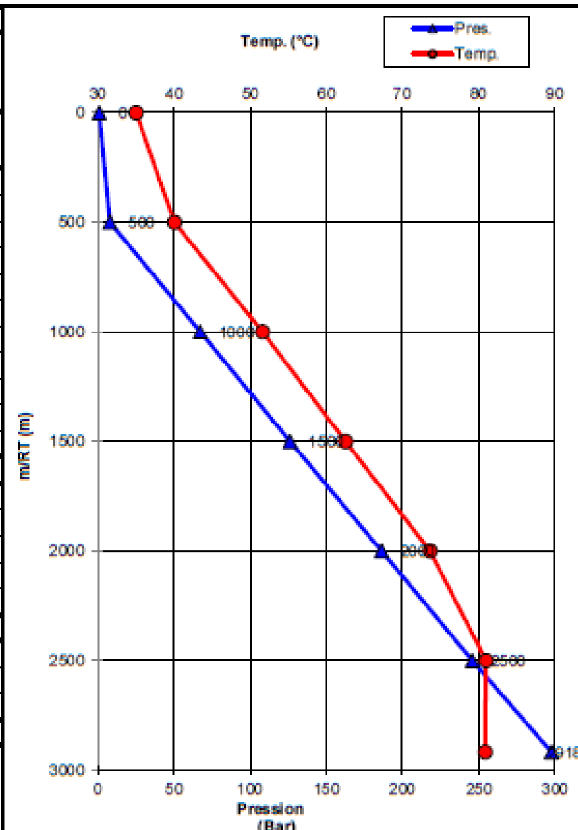


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Figure 0.3 Reservoir Pressure from SFNE 07 static gradient survey