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Presented By:

MESKINE ABDELFETTAH et ZEHANA MOHAMED TAHER

-TITLE-

Production wells optimizing in GASSI TOUIL field with Water& Gas Shutoff, Sucker Rod Pump and Electrical Submersible Pump

President:	**CHEIKH SABRINA**	**UKM Ouargla**
Advisor:	**BOUTALBI MOHAMMED CHAKER**	**UKM Ouargla**
Co-Advisor:	**BRAHMIA NABIL**	**UKM Ouargla**
Examiner:	**BOUCHERIB ABDELOUAHAB**	**UKM Ouargla**

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To the cherished pillars of my life,

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under the warm embrace of **our classroom**, we wove memories together. Here's to the laughter, tears, and shared life that will forever linger in our hearts.

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With a heart brimming with emotion

[MESKINE ABDELFETTAH]

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under the warm embrace of **our classroom**, we wove memories together. Here’s to the laughter, tears, and shared life that will forever linger in our hearts.

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[ZEHANA MOHAMED TAHER]

Abstract

This work delves deep into the optimizing of wells in the GASSI TOUIL field, focusing on both eruptive wells GT03, GT30, GT45. we evaluate that GT03 (non-candidate for the gas shutoff operation), GT30 and GT45 have been successful in shutting off the gas, which have improved the oil production rate (GT30 from 54.24 m3/d to161.5 m3/d and GT45 from 7.79 m3/d to 21.58 m3/d), based on PLT data and the evaluation of this data with EMERAUD software. And non-eruptive wells (HC 05 and GT35) through artificial lift techniques: well, HC05 is improved using SRP to optimize the oil flowrate from 10.943 m3/d to 24.048 m3/d, and well GT35 is upgraded with an ESP with modeling done via PIPESIM software to optimize the liquid flowrate from 97.85 m3/d to 170 m3/d.

Key words: optimizing, EMERAUD, PIPESIM.

Résumé

Ce travail approfondit l'optimisation des puits dans le champ de GASSI TOUIL, en se concentrant sur les types des puits éruptifs GT03, GT30, GT45. Nous constatons que GT03 (non éligible à l'opération d'arrêt de gaz), GT30 et GT45 ont réussi à stopper le gaz, ce qui a amélioré le taux de production de pétrole (GT30 de 54,24 m3/j à 161,5 m3/j et GT45 de 7,79 m3/j à 21,58 m3/j), en se basant sur les données PLT et leur évaluation avec le logiciel EMERAUD. Et deux puits non éruptifs (HC 05 et GT35) à l'aide de techniques de levage artificiel : le puits HC05 est amélioré en utilisant le SRP pour optimiser le débit d'huile de 10,943 m3/j à 24,048 m3/j, et le puits GT35 est équipé d'un ESP avec une modélisation réalisée via le logiciel PIPESIM pour optimiser le débit de liquide de 97,85 m3/j à 170 m3/j.

Mots clé: optimisation, EMERAUD, PIPESIM.

ملخص

يتناول هذا العمل تحسين آبار حقل قاسي طويل بتركيز على الآبار الثورية GT03 ، GT45 و GT30 . تم تقييم أن GT03 (غير مرشح لعملية إغلاق الغاز)، و GT30 و GT45 نجحنا في إيقاف تدفق الغاز، وهو ما ساهم في تحسين معدل إنتاج النفط (GT30 من 54.24 م3/يوم إلى 161.5 م3/يوم و GT45 من 7.79 م3/يوم إلى 21.58 م3/يوم)، بناءً على بيانات PLT وتقييمها باستخدام برنامج EMERAUD. كما تم تحسين الآبار غير الثورية HC 05 و GT35باستخدام تقنيات الرفع الصناعي: تم تحسين البئر HC05 باستخدام SRP لتحسين معدل تدفق النفط (من 10.943 م3/يوم إلى 24.048 م3/يوم)، وتم ترقية البئر GT35 بوحدة ESP مع إجراء نمذجة باستخدام برنامج PIPESIMلتحسين معدل تدفق السائل (من 97.85 م3/يوم إلى 170 م3/يوم).

كلمات مفتاحية: تحسين, EMERAUD, PIPESIM

Contents

List of figures

List of tables

Glossary

API	American Petroleum Institute
CCL	Casing Collar Locator.
CFS	Continuous Flow Meter Spinner.
d	Density.
Fdd	Differential pressure fluid density
GR	Gamma ray.
GT	GASSI TOUIL
HC	HASSI CHERGUI
LCP	Perforated and slotted liner
m	meter
PLT	Production Logging Tool
Pg	Reservoir pressure (psig).
PVT	Pressure, volume, temperature.
Qg	Gas flow rate (m^3/d).
Qo	Oil flow rate (m^3/d).
Qw	Water flow rate (m^3/d).
RPS	Revolutions per second.
SIP	selective Inflow Performance
WC	Water Cut.
AOFP	Absolute Open Flow Potential
PR	Average Reservoir Pressure
BHP	Bottomhole Pressure
cP	Centipoise
CT	Coiled Tubing
ESP	Electrical Submersible Pump
ft	Feet
GOR	Gas – Oil Ratio
WOR	Water – Oil Ratio

GL	Gas Lift
hp	Horsepower
HP	Hydraulic Pump
IPR	Inflow Performance Relationship
ID	Inside Diameter
mD	Millidarcy
OD	Outside Diameter
PBR	Polish Bore Receptacle
psi	Pound per Square Inch
PI	Productivity Index
PCP	Progressive Cavity Pump
SRP	Sucker Rod Pump
VSD	Variable Speed Drive
Pwf	Well Flowing Pressure
So	Oil Saturation
Sw	Water Saturation
TAC	Triassic Carbonate
TAGI	Lower Triassic Argillaceous-Sandy
TAGS	Upper Triassic Argillaceous-Sandy
WOC	Water oil contact.

Chapter I: introduction

1. Problem description

In the context of the Algerian energy industry, the hydrocarbon sector plays a prominent role, a legacy of the nationalization of 1971. The national energy strategy focuses on the efficient exploitation of hydrocarbon reserves, deploying sophisticated recovery methods to optimize production and ensure its sustainability.

The GASSI TOUIL field, located in Hassi Messaoud, is known for its remarkable petrophysical properties. However, it faces challenges such as managing gas/oil and water/oil interfaces, which result in the intrusion of these fluids into the wells, thereby reducing the oil flow rate. Furthermore, the pressure drops resulting from natural depletion can lead to a production decline. What are the solutions proposed to utilize the best production optimization techniques for the Gassi Touil wells?

2. Research objectives

In this work, we provide a comprehensive analysis of the optimal solutions we have identified, to examining an oil production optimization state.

- The application of water and gas shutoff in eruptive wells to optimize the oil rate
- Application of SRP and ESP in non- eruptive wells to optimize the production rate

3. Outline of Dissertation

Chapter II This chapter explained the literature review of water and gas shutoff

Chapter III This chapter explained the literature review of Sucker Rod Pump and Electric Submersible Pump.

Chapter IV This chapter presents the case study to optimize production flowrate using water and gas in eruptive wells and artificial lift methods in non-eruptive wells in the GASSI TOUIL field.

Chapter V The conclusion of this research is described in the final chapter. Also, the future research topics are suggested1958, with 32 gas and condensate wells drilled [1]

Chapiter II: Literature Review of Water and Gas Shutoff

1. Overview of production logging Tool

Introduction

Production logs provide a point-by-point diagnostic information on fluid arrivals such as water, oil, and gas, giving an indication of the efficiency of perforations as essential tools in forecasts. The efficiency of simulation operations has been greatly improved due to the better understanding of the stress state of formations, through the use of numerical modeling, real-time monitoring of various parameters (bottom hole pressure, flow rate, density, temperature) during PLT operation.

Production Logging Tool

A. Definition of PLT

The PLT represents all the tools that are used to continuously record physical parameters as a function of depth in order to create different production profiles. Indeed, these tools constitute a reliable means to solve many production problems [6].

B. Objectives of PLT

Among the main uses and objectives of PLT, we can mention:

a) **Reservoir Evaluation**

- Establish the flow profile in the reservoir.

- Measure the effluent rates from each interval.

- Detecting production issues:

• Gas breakthrough

• Water influx

• Cross flow

b) Diagnosing faults that affect the proper functioning of the well

Among these faults are mentioned:

- Leaks in tubing, casing, and packer.

- Intervals responsible for the influx of undesirable fluids.

c) Evaluating well treatment

For the various treatments performed in the well, the PLT is used to determine the flow profile and productivity or injectivity index for the different zones neighboring the well before and after stimulation [6].

C. Measures and various components of the PLT tool string

The PLT tool string consists of several sensors through which recordings can be made while descending and ascending along the wells at different speeds [3]. It allows obtaining the following information:

a). Flow rate recordings using impeller rotation.

b). Fluid density recordings using differential pressure and Gamma Ray attenuation.

c). Temperature measurements in the well using resistance variation.

d). Pressure measurements in the well using strain gauges and crystal gauges [2].

D. Different types of conventional probes and optional tools can be mentioned

- Spinner

- In-line Spinner (secondary spinner).

- Caliper.

- Temperature.

- Pressure.

- Density.

- GR/CCL: Depth by correlation.

- Telemetry.

- Water and Gas hold-up (Fig.1)

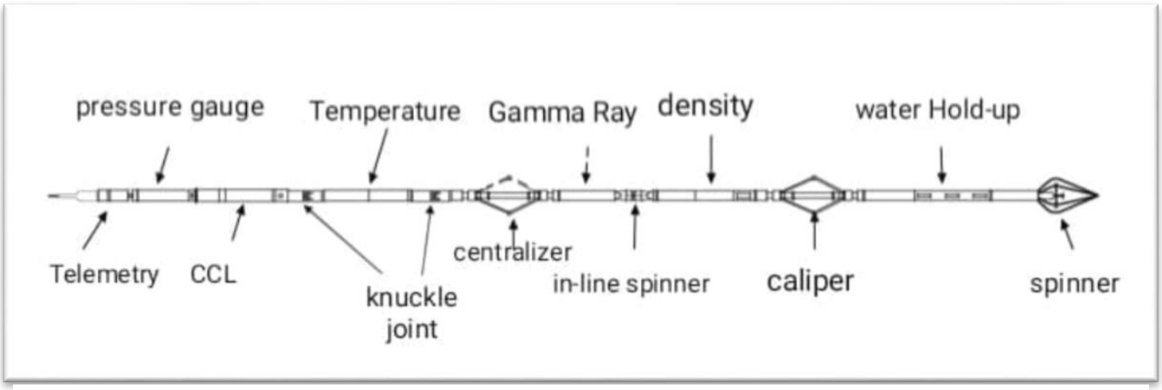


Figure 1: The PLT Tool Train [2].

2. Water shutoff

2.1 Water Production

It is the water that is typically associated with oil production in the late stages of water-flooding operations or from active aquifers. It is also the water produced at a low water/oil ratio (WOR) which maintains the profitably of a production well. Attempts to reduce this kind of water production leads directly to reduction in the oil production. On the contrary, unwanted water production is the type which needs to be eliminated and reduced in order to increase the productivity and the profitability of the production wells [3].

2.2 Sources of Unwanted Water Production

In water-flooding operations, the aim is to mobilize the oil in the matrix rock toward the production wells and to maintain the pressure of the reservoir. Open fractures and high permeability layers usually reduce the efficiency of flooding operations and leads to poor conformance. As mentioned previously, the fluid tends to take the paths least resistance and the injected water, as a result, goes to the open fractures and high permeability formations instead of matrix rock to displace the oil [3].

a) In some cases (As seen in Fig.2), the water injection well happens to be connected with the production well through an open fracture or features which are known also as ‘thief zones’ [3].

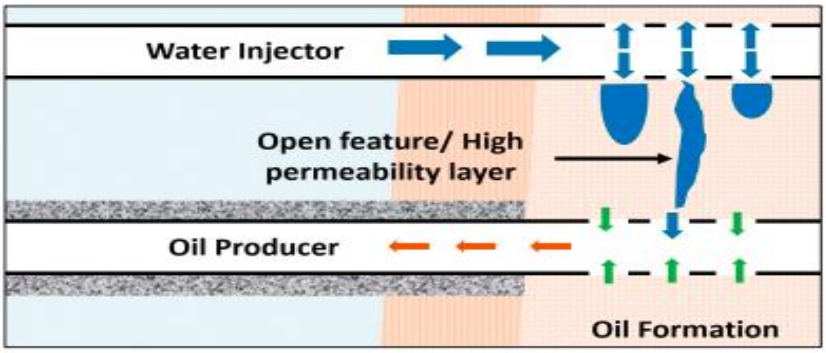


Figure 2: Example of a water injection well connected to an oil producer well through an open feature/high permeability layer [3].

b) Open features also can result in an excessive amount of water if they are connected to the aquifer. Additionally, fractures and open features can contribute to unwanted water production when they are connected to water formations/zones. Gas hydrate reservoirs can be also a main source of excessive water production when dissociated (Fig.3) [3].

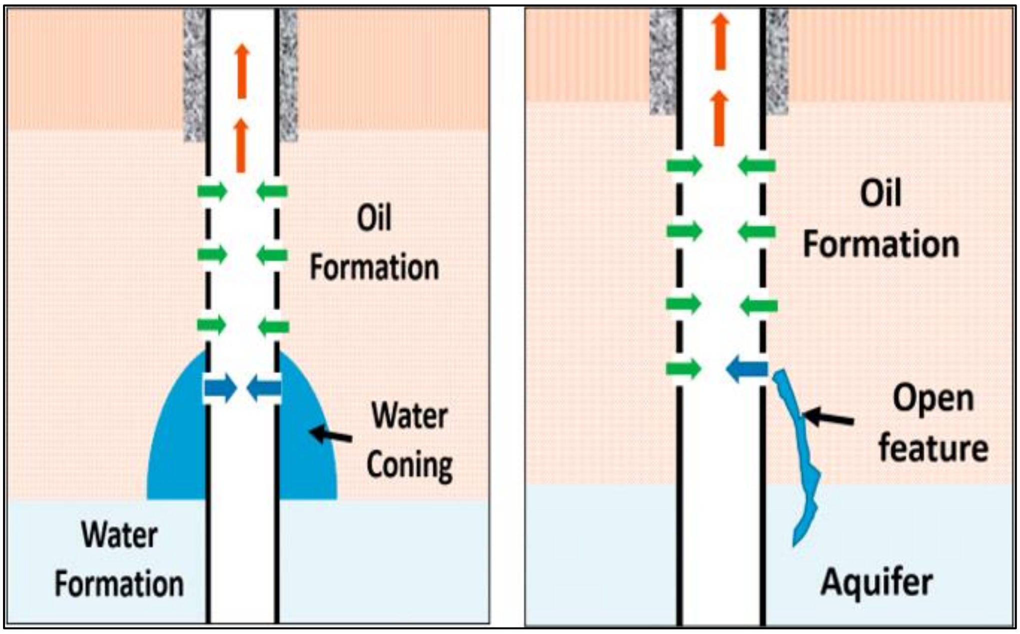


Figure 3: water conning and an oil producer connected to an aquifer through an open feature [3].

c) water coning. This situation usually occurs when the production zone is near the aquifer or water formations with a decent permeable connection between the oil production zone and the water formation. Coning arises with the drawdown of the pressure which encourages the water to migrate to the wellbore from the bottom (Fig.3) [3].

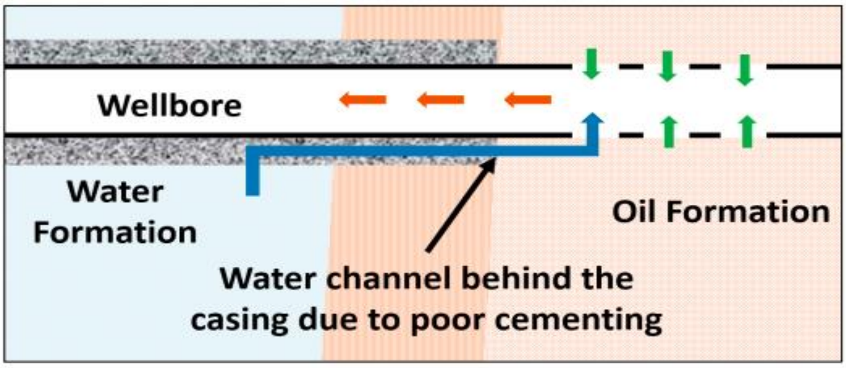


Figure 4: Poor cement behind the casing with a channel connecting water source to the wellbore [3].

d) poor conditions of the nearby wellbore can occur as a result of casing leaks or bad cement jobs behind the casings which usually creates channels connecting the unwanted water production formations/sources with the wellbore. The casing and the cement job behind the casing are supposed to create a seal from such unwanted layers (Fig.4 and 5) [3].

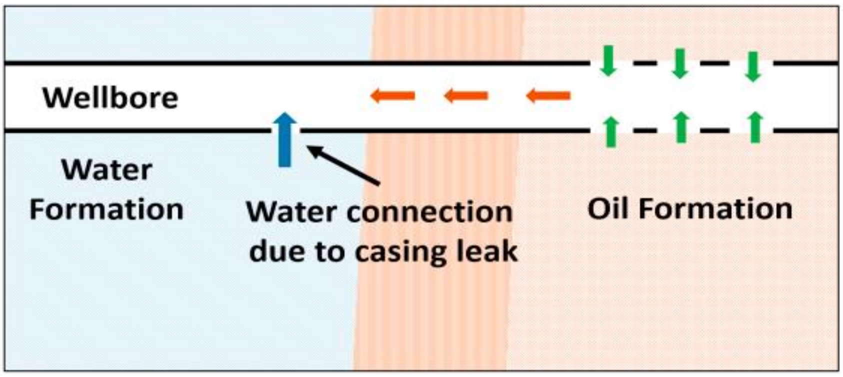


Figure 5: Casing leak connecting the wellbore with water formation [3].

2.3 Water shutoff operation

Water shutoff operations focus on eliminating unwanted water production, which is also called ‘bad water’.

Reducing excessive water production usually starts with gathering all available reservoir and production data. Then logging tools are used to locate the water entry points. Finally, based on the results, a proper shutoff method is used. The most important part in any water shutoff operation is the accurate diagnosis of the problem. It is essential to know the water entry point, the heterogeneity of the reservoir rocks, dominant production mechanisms, and the schematics of the wellbore. In fact, all available information about the well is considered valuable, like drilling operations reports, logs, and production history. The reason behind that is that every well would have its own workflow based on it is properties, history, and reservoir heterogeneity. Accurate investigation leads to success in the water shutoff operation, increasing oil production, and saving water handling costs [3].

Production logging tools in production wells usually are used to identify the water production zones, which is an important step in planning for an optimized water shutoff operation. For water injection wells, water flow logs are used to identify the thief zones. That is due to the complicity of the wellbore, flow regimes, and their effects on obtaining the required information. Luckily, advanced production logging tools can be used to identify the entry points as well as the rates [3].

Fiber optics technologies are used nowadays along with logging tools to ensure high-quality real-time data that help in accurately identifying the water entry zones [3].

For channeling behind the casings, running cement bond logs or ultrasonic pulse-echo logs plays a vital role in ensuring the integrity of the cement job behind the casing. Those kinds of logs evaluate the bonding properties of the cement job behind the casing and point out bad cement areas. For casing leaks, production, temperature, and noise logs are all means of identifying the sources of leaking [3].

Chemical solution

Far from the wellbore, in the reservoir or near the wellbore, water shutoff operations can be performed by several chemical treatments. Those chemical solutions lead to better conformance in the reservoir as well as blocking the unwanted water production zones [4].

The idea is to be able to close the paths of least resistance in front of the water by reducing their permeability in order to prevent the water from coming to the wellbore through them. Also, they aid in forcing the water to mobilize and displace the oil in the reservoir. In other words, the aim is to block the open features and high permeability channels to force water to go toward the harder path to sweep oil from the matrix rock that results in higher overall economical returns than producing oil from fractures [4].

In fact, induced formation damage can be used as an effective solution to control the unwanted water production. The results of chemical solutions can be achieved in a couple of months to years, depending on the nature of the reservoir and the properties of the injected chemicals. The main advantage that chemical water shutoff operations have over mechanical operations is that they solve the problem of the unwanted water production instead of hiding it under or behind a plug, packer, or tubing patch. Injected chemicals can reach water features in the reservoir and reduce the permeability, resulting in closing them entirely [3].

They also have the freedom of moving between the layers and features which helps in reaching to far extents and completely closing them. Another use of chemical injection is to increase the viscosity of the injected fluid which leads to a better sweeping efficiency and eventually reduces the production of unwanted water. The success of chemical injection operations depends on the knowledge level of the reservoir and its characterizations, chemical properties, and accurate placement of the injected chemicals [3].

a) Gel

Gel injection is used to reduce the water oil ratio and increase the conformance of the pattern. That happens through the ability of the gel to reduce the permeability and block the open features, fractures, and high permeability water zones. It can be applied in the wellbore, near the wellbore, and far from the production well through injection wells. It is very effective in reducing the permeability of unwanted zones and has proven its ability to improve the sweep efficiency and shutting-off the unwater water zones [4].

The injected gel is mainly made of water, small volumes of polymers and crosslinking chemical agent. Gel treatments can completely seal off layers; therefore, they are considered aggressive and risky conformance control operation. On the other hand, polymer gel injection is considered relatively cheaper than other improved oil recovery operations [4].

Gel injection operations are divided into three main stages: modeling, designing, and executing.

The first step is to model the gel injection operation by using simulation software, which is an important step for designing the program of gel injection operation. In this stage, all the available information about the reservoir and the well are considered valuable, such as: reservoir parameters, water entry points, drilling operations reports, logs, and production history [4].

The second step is to design the properties of the polymer gel fluid. Injecting gel in the reservoir depends on four properties. First one is the viscosity of the gel at the time of injection which helps in directing the gel to the lager and least resistance paths [4].

Second is the nature of the gel phase which is usually chosen to be the aqueous phase since the water is the desired phase to be shut off. Third is the density of the gel.

It very important to be designed carefully and based on the density of the formation water to avoid losing the effectiveness of the gel treatment. Fourth is the setup time or injection time. Longer injection time leads to more success in allowing the gel to seal off larger features and least resistance paths [4].

b) Polymer Flooding

This technique is applied to increase the viscosity of the drive fluid (water) which helps in mobilizing and displacing the oil in the reservoir matrix rock. This technique is usually applied in the reservoir far from the production wells through water injection wells to achieve better sweeping efficiency in the reservoir. That eventually leads to preventing excessive water production. The usage of polymer flooding is very common among the oil operators and it can be prepared by dissolving the polymers in the injected water and inject it through injection wells. Polymers used in this technique are usually two types: biopolymers and synthetic polymers. Polymers can also play a role in reducing the permeability if the molecular weight is increased. Finally, based on the characteristics of the reservoir and the economics of the operations, the right polymer is chosen in case of chemical injection. There are other chemical techniques for water shutoff operation such as resins, solid particles, and foams which are also effective in obtaining better conformance and enhance the sweep efficiency [3].

Mechanical solution

Controlling the water production mechanically is known for it is fast outcomes as well as its cheap costs. It is usually a rig less job, which means a lower cost. Mechanical water shutoff operations are preferred by operators since they are relatively cheaper than chemical solutions. Once more, an accurate diagnosis is essential before attempting to apply those solutions, since it can result in losing the oil production from the well. That can be achieved, as mentioned previously, through running logs to identify the water production zones [3].

In the case of mechanical shutoff operations, there are some factors affecting the success of them. One of them is the setting depth of the plug or the packer can be wrong due to inaccurate readings from the coiled-tubing meter. The reservoir conditions also play a great role in affecting the operations, since a cross flow between the layers can happen and leads intervention to failure. The wellbore condition is another vital factor which needs to be considered. Scale presences in the tubing can result in failure of the operations, since it can create an obstacle while running the plug or the packer downhole. Wells with high deviation angles can be challenging to run in hole with coiled-tubing since they can get stuck a lot [3].

a) Plugs and Packers

Packers and plugs are successful in eliminating the production from unwanted water zones. This hardware is known for being economical and reliable in achieving isolation since it can be installed without pulling the production tubing and without the drilling rig. They can be installed by using coiled tubing which can run them through the wellbore. Also, the results can be achieved relatively fast, in a couple of hours to days. Simply, the concept of packers and plugs is a small diameter element, mainly rubber, which can expand downhole the wellbore into larger diameters, creating a seal and isolating the well from unwanted features or zones [4].

There are different types of packers and plugs with different properties and setting techniques. Some elements expand by interacting with certain types of fluids (oil, water, or hybrid) which are known as ‘swell able packers. They also depend on pre-designed properties like temperature, pressure, and salinity of the formation fluid. That can be a disadvantage in some cases and leads to failure in setting the element. If those properties are not accounted for accurately, that might lead to a faster inflation of the elements or even slower inflation than expected. In the worst-case scenario, the element might not inflate at all. Other packers and plugs inflate by applying pressure on the element in order to expand and seal. These types of plugs usually inflate by pumping darts, steel balls, or fluid to apply pressure on the rubber element and allow it to expand and increase its diameter. Packers and plugs can be used to isolate unwanted water production inside the wellbore in certain cases. An easy example would be an open-hole well completion and the water zone are identified to be from the bottom of the well. A bridge plug can be installed to isolate the bottom section and shut down the additional water production to aid the production performance from upper oil zones. The difficulty increases if the water source happens to be in the middle or at the top part of the production section of the tubing in the reservoir section. In that case, a blank pipe with upper and lower packers, with a pre-designed length, can be installed to isolate the water production area without compromising the lower and upper oil production zones. In the case of a multi-lateral wells, if one of the laterals is watered-out or producing extreme amounts of unnecessary water, it can be abandoned by setting a plug to isolate it from other laterals. The usage of packers is also used in early stages of the well life, specifically in the completion stages after drilling. That is a common practice for operators who have a reasonably decent knowledge of the expected features and layers of their reservoir. Also logging while drilling tools can be an asset by identifying the open features which might be the future reason for bad water production. After drilling the well and collecting the data, a pre-perforated liner can be installed with packers to produce only the good layers and isolate the risky formations. Once more, an accurate and cautious pre-design of the job is essential for designing the elements to avoid failures (As seen in Fig.6) [3].

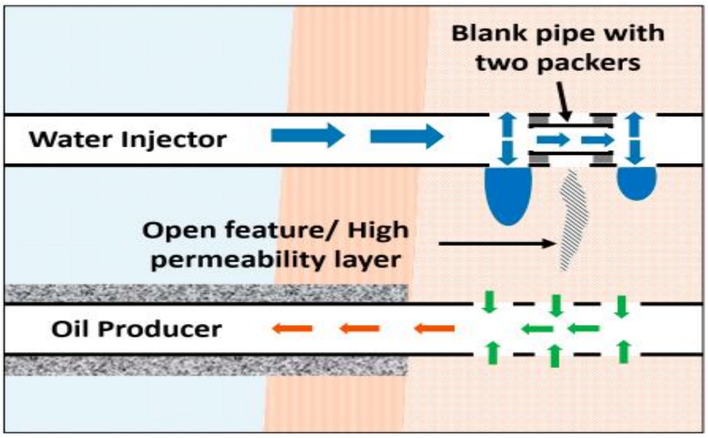


Figure 6: Using a plug to shut off the production of water from the bottom [3].

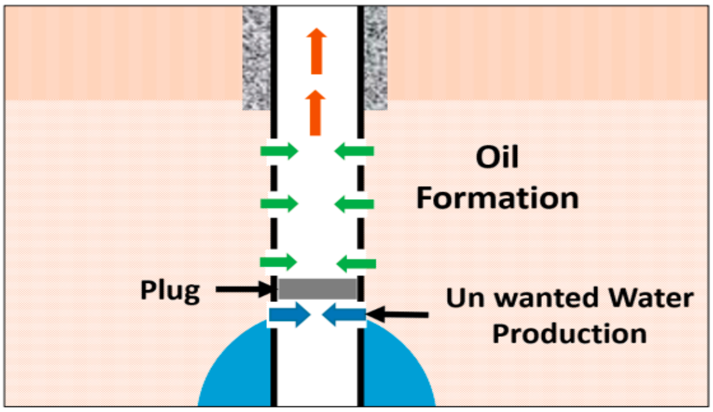


Figure 7: Two packers Isolation Technic [3].

for water injection wells, those plugs can be used to ensure better conformance outcomes and to eliminate the production of bad water from the production wells through thief zones, high permeability layers, or connected open features. For example, if any of the previous features have been identified in the injection profile of water injection well, plugs can be used to isolate injected water from going into them. If there is an open feature at the bottom of a water injection well, a plug can be installed to isolate the bottom section, to avoid wasting the injected water and direct it into oil matrix rocks instead (Fig.7). Similarly, if the feature happens to be at the middle or the top of the injection profile, a blank pipe with upper and lower packers can be installed to isolate the thief zones from stealing the injected water without compromising the conformance and the sweeping efficiency of the field [3].

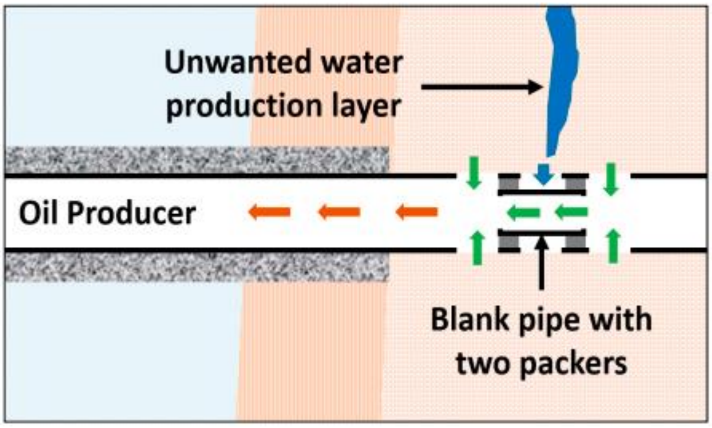


Figure 8: Two packers above and below a blank pipe to avoid injecting the water in open features or high permeability layers [3].

Other than that, inflatable packers are also used in chemical injection for water shutoff operations. As mentioned previously, chemicals can be used in the near wellbore area to control and shut off the unwanted water production. However, this operation considered risky because of the high cost and the risk of injecting the chemicals into the oil production zones. Therefore, packers are used to direct the flow of the injected chemicals into the desired layers and prevent fluid from going into the production formation. Packers create a seal by inflating and isolating the upper and bottom intervals to make sure that chemicals do not bypass to oil zones [3].

b) **Tubing Patches**

This method is mainly used for fixing well integrity issues particularly casing leaks.

The casing leaks problems are common in old wells and the wells which are completed in formations with corrosive gases like H2S [4].

If the source of the unwanted water was found to be from a leak in the casing, squeezing cement or resins patches is considered to be a suitable solution. This method can be applied only after identifying the exact location of the leak through the methods discussed earlier. Squeezing jobs can be performed by rigs or sometimes with current technologies can be a rig-less job. Usually, inflatables are used to direct the patches toward the leaking point.

For small leaks, fine cement particles are squeezed to fix the well integrity issue as well as creating a seal [4].

3. Gas shut off

3.1 Gas production

In the context of hydrocarbon extraction, gas often emerges as a byproduct during the latter phases of oil production, particularly prevalent in scenarios involving advanced gas injection techniques or the presence of dynamic gas caps. Additionally, gas is generated at a favorable low gas-to-oil ratio (GOR), which is instrumental in sustaining the economic viability of an oil-producing well. Proactive measures aimed at curtailing this specific category of gas production can inadvertently precipitate a decline in oil output. Conversely, the mitigation or outright elimination of superfluous gas production is imperative for augmenting both the efficiency and fiscal performance of oil wells [2].

3.2 Unwanted Gas Production in oil wells

A. Gas Injection in Gas Cap

(As seen in Fig. 9), When gas is injected into the gas cap, it acts as a driving force for the oil towards the well. To enhance this process, an injector well is placed in the gas cap. As oil is extracted from the reservoir, the gas above it (known as the heading gas) expands rapidly to fill the available space. This leads to the gas/oil interface forming around the perforated area, where the gas accompanies the oil production. At this stage, gas coning occurs, significantly increasing the gas-to-oil ratio (GOR) in the produced fluids, posing a risk of gas entry issues for the producing well [2].

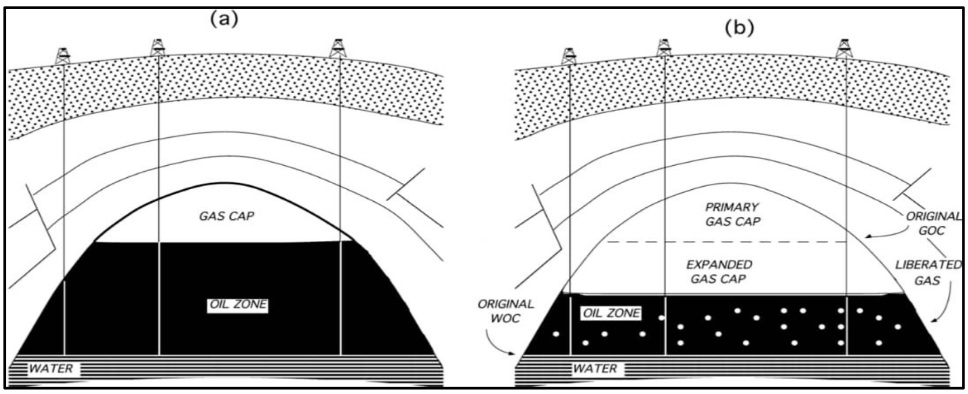


Figure 9: Oil-gas contact displacement [5].

B. Direct Gas Injection into Oil

Directly injecting gas into the oil creates a fast path to the producing well, as gas moves swiftly along the layer's roof. Consequently, the gas content in the produced fluids rises rapidly, elevating the GOR and potentially causing gas penetration problems for the producing well [5].

C. Release of gas dissolved in oil

When the reservoir pressure drops below the bubble pressure, dissolved gas is released, leading to a fast increase in the gas content of the produced fluid. This elevated GOR poses a risk of gas penetration issues for the producing well (fig.10) [5].

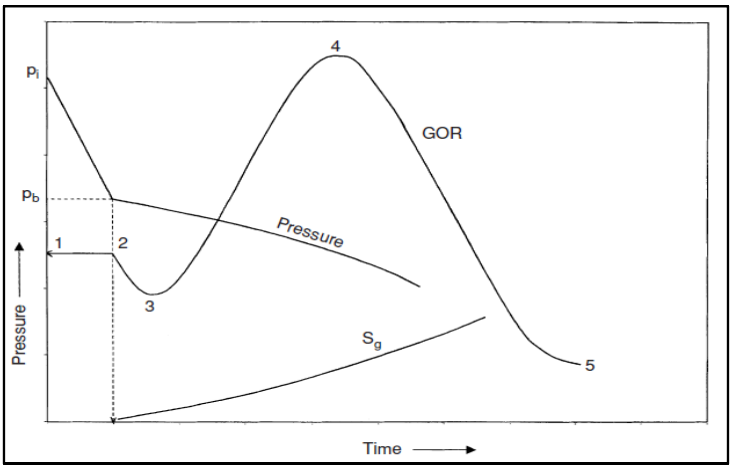


Figure 10: How Pressure and Gas-Oil Ratio (GOR) Shift with Reservoir's Total Oil Production [5].

3.3 excessive Gas-Oil Ratio Sources

The Gas-Oil Ratio (GOR) in a production well refers to the volume of gas produced relative to the volume of oil produced. A high GOR indicates a larger proportion of gas relative to oil. A higher GOR indicates that there is an excessive gas production, which can lead to reduced oil production efficiency [5].

There are three main sources of high GOR in a production well:

Gas Coning

Gas coning occurs when the pressure drop at the perforations exceeds the pressure head resulting from the difference in densities between the overlying gas and the oil times the oil column height allowing gas to be pulled downward into the perforations (fig.11) [5].

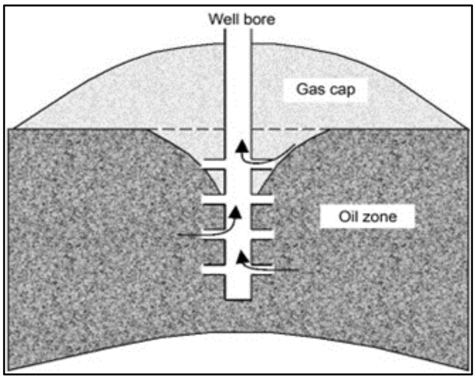


Figure 11: Gas production due to gas coning [5].

Channeling

Channeling is typically described as the movement of fluids within the annular space of production tubing due to poor hydraulic isolation between the tubing, cement, or formation (Fig. 12) [5].

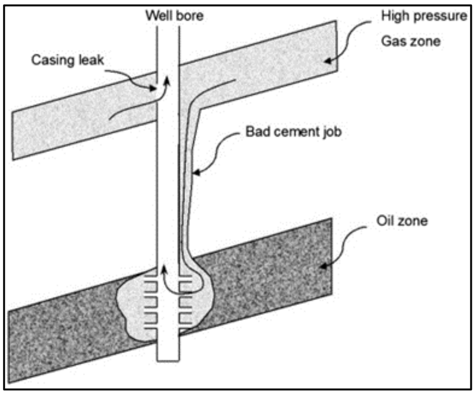


Figure 12: Gas production due to channeling behind the casing [5].

preferential flow through high-permeability zones

In oil reservoirs, high-permeability zones are areas where the rock allows fluids to pass through more easily. These zones can cause gas to move faster than oil, leading to a situation where gas arrives at the production well before the oil. This is known as early gas breakthrough. When this happens, the amount of gas produced in relation to oil increases, which is measured by the Gas-Oil Ratio (GOR). A high GOR can be challenging because it means more gas is being produced than desired, which can complicate the oil extraction process and affect the overall efficiency of the oil well (fig.13) [5].

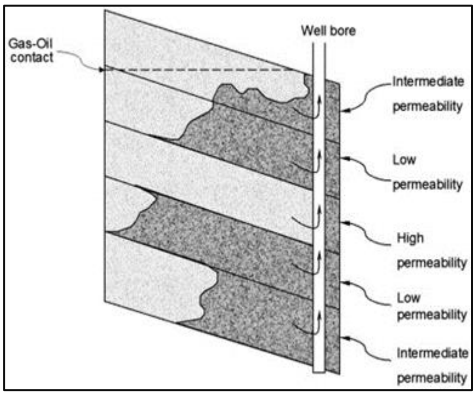


Figure 13: Gas production due to preferential flow through high-permeability zones [5].

3.4 Consequences of increasing Gas-Oil Ratio

Well bottom flow pressure (BHFP): decreases.

Tubing head pressure (THP): increases.

Tubing head temperature (THT): decreases.

Pressure difference at Duse (dP. choke): increases.

Temperature difference at Duse (dT. choke): increases

3.5 Cause of Excessive Gas Breakthrough

The causes of gas breakthroughs in oil reservoirs are indeed multifaceted and can be broadly categorized into issues related to the reservoir itself and those associated with exploitation techniques [2].

1.Reservoir-Related Causes

- Effect of Permeability

High permeability can lead to faster flow of injection fluids, causing early breakthrough at production wells.

- Cracked Tank and Leakage

Tectonic activities can create faults and cracks, which act as preferential paths for fluids, potentially compromising the integrity of the well.

- Hydraulic Fracturing

This method can create pathways between oil and gas drains, enhancing gas flow but also potentially leading to premature breakthroughs3.

2.Exploitation-Related Causes

- Production Flow Rate

High flow rates can create a strong vertical pressure gradient, accelerating the extraction process and potentially leading to an overproduction of injected fluids1.

- Injection Rate

Maintaining reservoir pressure is crucial, and the injection rate must be balanced with the oil production rate. The continuous extraction of oil leads to the reduction of its volume inside the tank this volume is immediately replaced by that of the injection. So, if the volume of fluid injected becomes greater than that of the oil produced, the danger of drilling the producing wells will increase which becomes worrisome, and this because of the poor prediction of the gas front [2].

3.6 Gas Shutoff Operation

Gas shut-off interventions in producer wells play a pivotal role in optimizing hydrocarbon production. These strategic measures aim to enhance oil recovery by managing excessive gas flow from specific intervals within the reservoir. By creating barriers using materials such as gels, polymers, or cement plugs, gas shut-off ensures a better balance between oil and gas production [2].

Chemical Solution

a) Foam Treatments

Foam treatments involve injecting a polymer-stabilized foam into the reservoir. The foam, created by combining polymers and surfactants [2].

Foam injection is a technique used to control excessive gas production in oil and gas wells. It works by reducing the gas-oil ratio and improving sweep efficiency during gas flooding operations. The foam acts as a blocking agent, reducing unwanted gas production and helping to direct the flow of injectants to the desired zones [2].

The process involves injecting a foaming agent into the well, which then mixes with the produced fluids to create foam. This foam has a higher apparent viscosity than the gas alone, which helps to control the flow within the wellbore. The increased resistance provided by the foam can divert the gas into less permeable zones, improving the overall efficiency of the recovery process [2].

the success of foam injection depends on several factors, including the properties of the foaming agent, the well's characteristics, and the precise application technique. Continuous monitoring and adjustment may be necessary to maintain the effectiveness of the foam over time [2].

Mechanical solution

A. Plugs and Packer

The installation of packers and plugs is mechanical solutions for gas shutoff and isolation operations inside the wellbore. They are successful in eliminating the production from excessive gas zones. They are commonly used by oil operators to aid the wells performance and shut off the excessive gas production. This hardware is known for being economical and reliable in achieving isolation since it can be installed without pulling the production tubing and without the drilling rig. Simply, the concept of packers and plugs is a small diameter element, mainly rubber, which can expand downhole the wellbore into larger diameters, creating a seal and isolating the well from unwanted features or zones [2].

Packers and plugs can be used to isolate excessive gas production inside the wellbore in certain cases. it's important to control gas zones that are above the oil zones. Special setups using packers (sealing devices) and pipes are used to isolate gas without affecting oil flow (As seen in Fig. 14) [2].

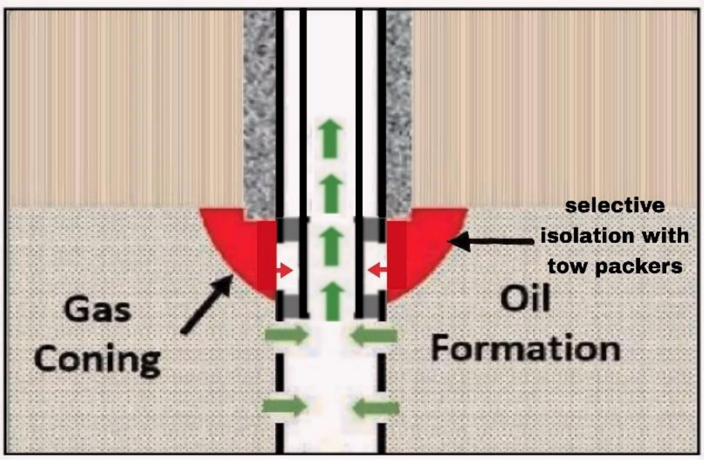


Figure 14: selective isolation of excessive gas production zone with tow packers [2].

For multi-lateral wells, we can put plugs to abandon gas-heavy lateral to keep it from affecting the others [2].

in a multi-zone vertical oil well production system, excessive gas entry has been detected in one of the zones, specifically in an oil-bearing layer located below other oil zones. To address this issue, it is practical to isolate the affected zone by installing a plug. This action would prevent further gas intrusion and preserve the integrity of the overall production system [2].

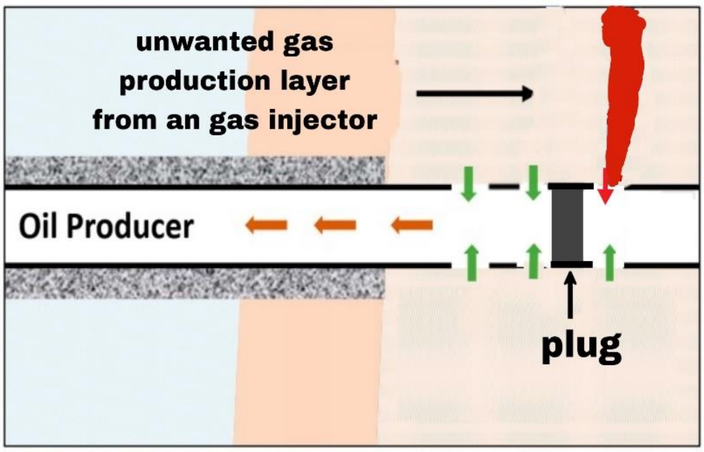


Figure 15: Using a plug to shut off the production of unwanted gas production layer from a gas injector [2].

Guided by reservoir data and drilling logs, allows for selective oil zone production while avoiding excessive gas areas. This careful planning and execution ensure the well's integrity and optimal oil production [2].

In gas injection operations (As seen in Fig.16), plugs and packers play a key role in ensuring the gas is injected into the correct zones for maximum efficiency. They help to prevent the gas from entering high-permeability areas or other unwanted zones. If such areas are detected within the well's injection profile, the appropriate plugs are used to seal them off [2].

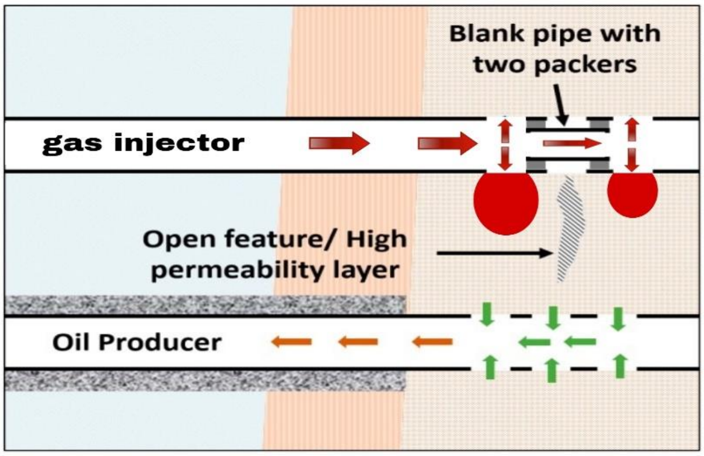


Figure 16: Two packers above and below a blank pipe to avoid injecting the gas in open features or high permeability layers [2].

For instance, a plug can be placed at the well's bottom to keep the gas within the oil-bearing strata, enhancing recovery. If the issue is higher up, a pipe section with packers on both ends can be inserted to block the middle or top sections, ensuring the gas aids in oil extraction without being lost to less productive areas (fig. 15) [2].

B. Tubing patches

If the source of the excessive gas was found to be from a leak in the casing, The application of cement or resin patches can restore well integrity by plugging the pathways through which gas might migrate. This method can be applied only after identifying the exact location of the leak through the methods discussed earlier (As seen in Fig.17) [3].

Squeezing jobs can be performed by rigs or sometimes with current technologies can be a rig-less job. Usually, inflatables are used to direct the patches toward the leaking point. For small leaks, fine cement particles are squeezed to fix the well integrity issue as well as creating a seal [3].

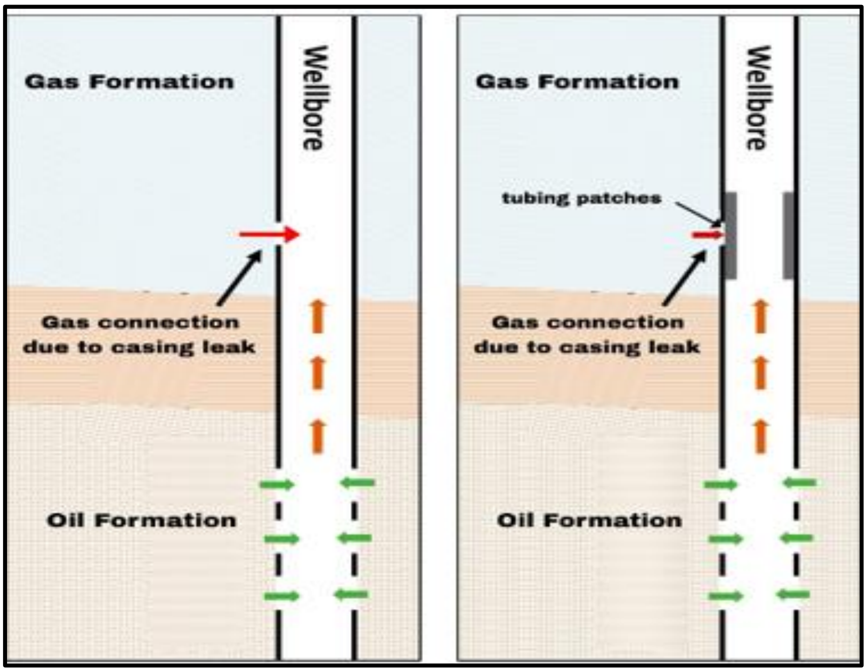


Figure 17: using casing patch to shut off the excessive from a casing leak [2].

In summary, chemical solutions are more permanent but riskier, while mechanical solutions are easier to implement. The choice between them depends on the specific well conditions and the desired outcome [3].

Chapiter III: Literature Review of Artificial Lift and Nodal Analyses

1. Introduction

The driving force that moves oil from a reservoir comes from the natural energy of compressed liquids stored in the reservoir. The energy that causes this is a result of pressure reduction between the reservoir and the wellbore edges. If the pressure reduction between the reservoir and the surface production equipment is significant enough, the fluid will naturally flow to the surface using only the natural energy provided by the reservoir. When the natural energy associated with the oil does not create enough pressure differential between the reservoir and the wellbore edges to lift liquids from the reservoir to the surface and into the surface equipment, or does not lead it to the surface in sufficient volume, the reservoir energy must be supplemented by a form of artificial lift.

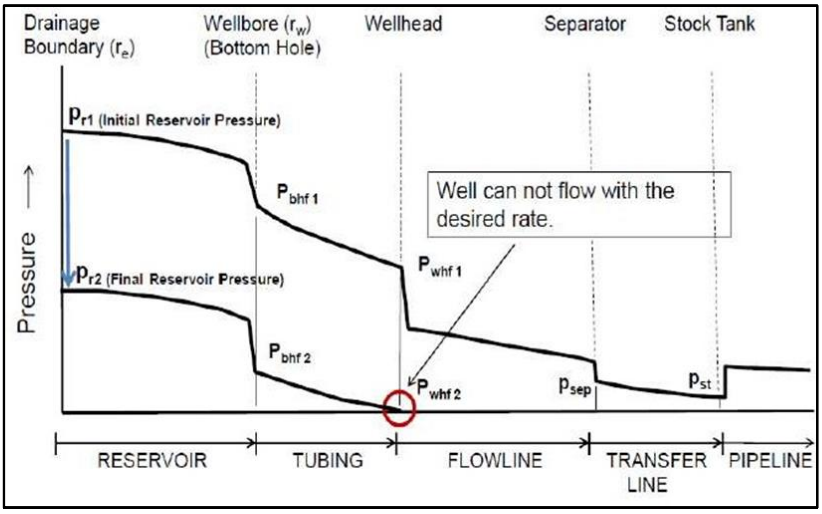


Figure 18: Profile Pressure Diagram for Production System [2].

The artificial lift methods are grouped into two categories, those that use pumps and those that use gas. The common artificial lift methods used worldwide are sucker rod pumps (SRP), electric submersible pumps (ESP), gas lift (GL), plunger lift (PLNG), hydraulic pumps (HP), and progressive cavity pumps (PCP). Sucker rod pumps are made of high-grade steel and are directed inside the production tubing to connect a subsurface pump to the operating unit. They are the most widely used artificial methods in the world [2].

2. Sucker Rod Pump

Sucker Rod Pump (SRP) is the simplest known artificial method and the most widely used choice of artificial methods. In the United States, 80%-85% of wells operate with sucker rod pumps, while this percentage is 50% worldwide. A pump pushes the fluid in the tubing to the surface [7].

2.1 Pumping Cycle

The main phases of the cycle are illustrated in the figure20.

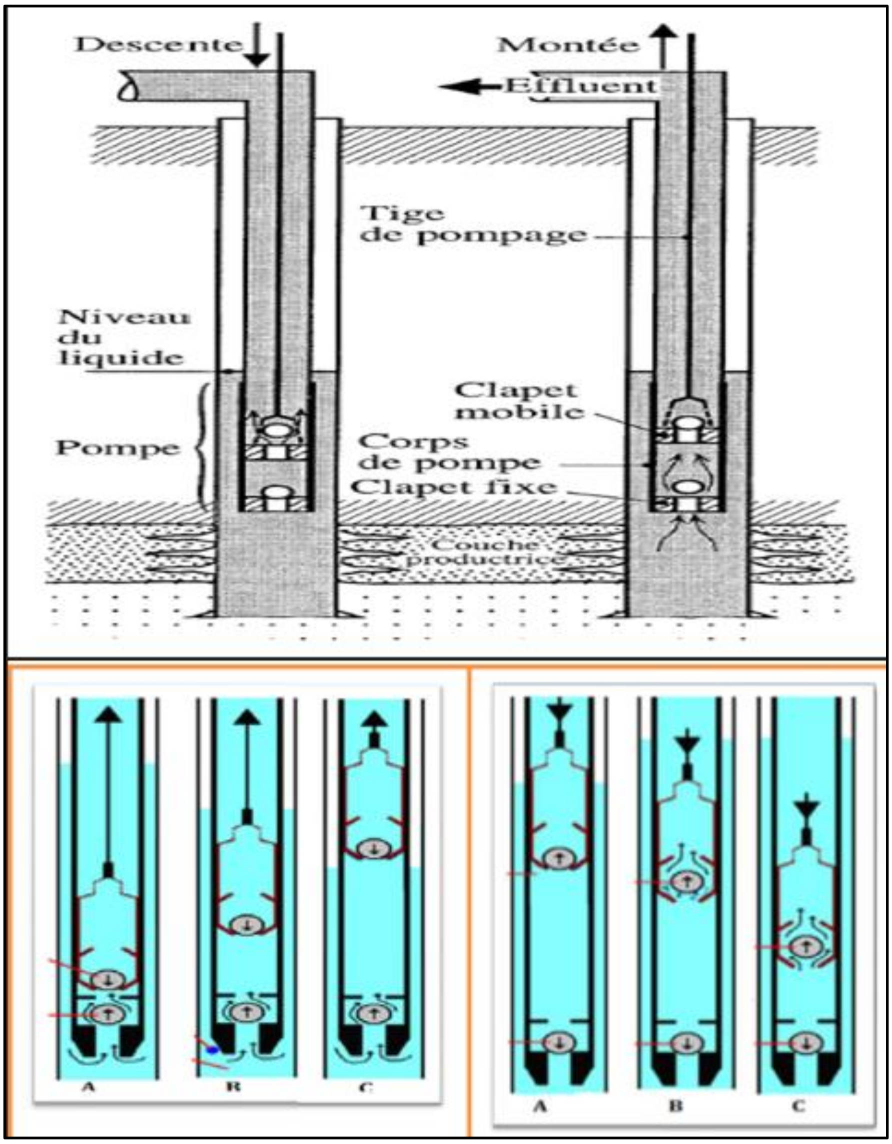


Figure 20: The Pumping Cycle (Sucker Rod Pump) [7].

a) Piston at the end of the downward stroke

The effluent flows through the open mobile valve while the weight due to the effluent in the tubing and the back pressure at the wellhead rests on the fixed valve which, consequently, is closed.

b) Piston at the beginning of the upward stroke

The mobile valve is now closed; consequently, the fluid load has been transferred from the tubing to the rod string.

c) Piston at the end of the upward stroke

The mobile valve is still closed, the fixed valve remains open as long as the layer is producing.

d) Piston at the beginning of the downward stroke

The fixed valve closes due to the pressure increase caused by the fluid compression between the fixed valve and the mobile valve [7].

2.2 Downhole Equipment

A. Gas Trap

To enhance the volumetric efficiency of the pump by reducing the gas flow, a gas trap can be installed on the tubing. This trap redirects gas back into the annulus above the pump, ensuring a pressure at the suction point that maintains the fluid in a single phase.

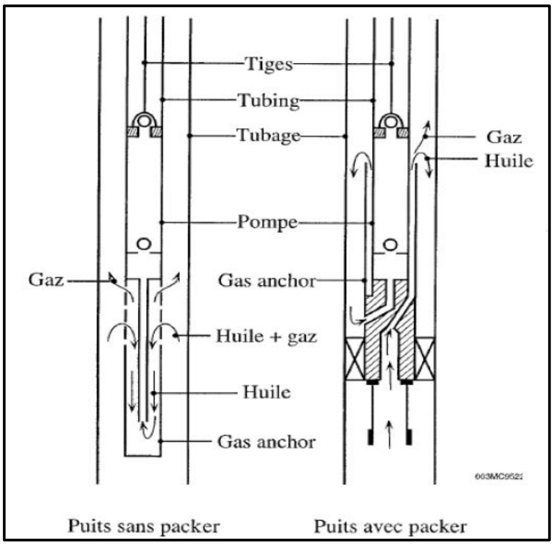


Figure 21: The Gas Trap (Sucker Rod Pumps) [7].

B. Downhole Pumps

Downhole pumps used in wells fall into two main categories:

- R Pumps (Rods pumps or inserted pumps)

These pumps are fully inserted at the pump depth using rods in the tubing, securely anchored in a designated seat, sometimes with a packer anchoring system. They may feature fixed cylinders anchored from the top or bottom, or movable cylinders with fixed pistons anchored from below.

- Tubing pumps

The pump body is first lowered into the tubing, followed by the piston screwed onto the rod ends.

Typically, the piston base includes a mechanism for installing and retrieving the pump's foot valve.

Pistons (plungers) are commonly metallic but can also incorporate synthetic linings. Piston diameters typically range from 3/4” to 4 3/4” OD (Outside Diameter).

Pump anchoring mechanisms come in metallic or cup-shaped designs, while the seats installed during completion are tailored to various setups. Pump valves consist of a ball and a metal seat enclosed within a cage, with options for single or double check valves for improved sealing [7].

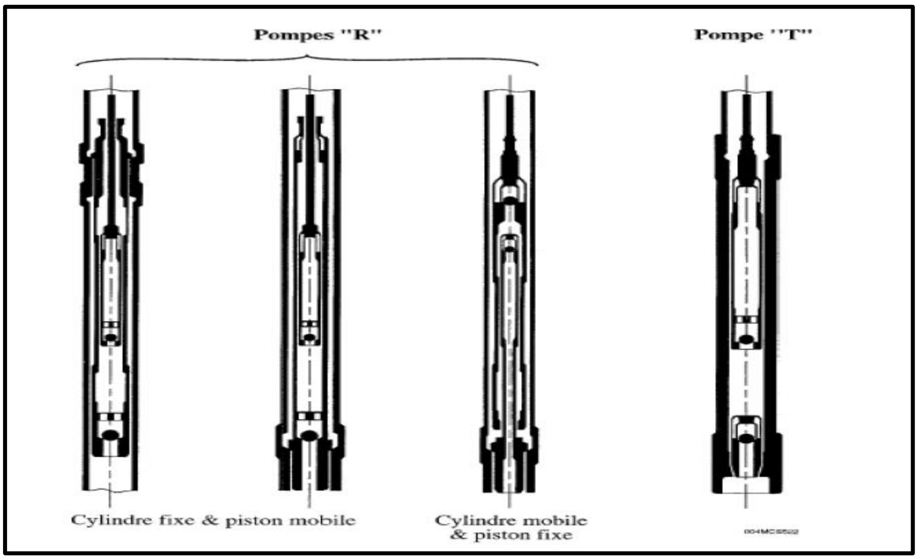


Figure 22: The two types of pumps [7].

C. Sucker rods

Endure tough working conditions, facing alternating stresses, corrosion, and vibrations. They are more prone to breakage when subjected to high maximum tension, a significant difference between maximum (upstroke) and minimum (downstroke) tension, and rapid pumping rates. To maximize production output, it's more effective to increase the pump stroke rather than the piston size or pumping speed. Typically, these rods are pushed back at the ends to create maneuvering squares and threaded tips, with a male thread at one end and a female thread at the other [7].

Figure 23: Pumping Rod Tip [7].

Rods are sized based on their diameter and come in the following options:

• Normal rods are available in sizes 5/8", 3/4", 7/8", 1", 1 1/8";

• Polished rods are offered in sizes 1 1/8", 1 ¼", 1 ½".

Standard lengths are 25 and 30 feet (7.60 m and 9.10 m), but there are also shorter rods (pony rods) for precise fitting.

D. Surface Pumps

d) The Gland

This component consists of fittings secured by a screw cap. The conical-shaped fittings are split to fit around the polished rod.

e) Pumping Unit

The pumping unit (see Fig.2335) is designed to support the rod string and provide it with a back-and-forth motion. It includes:

- An electric, gas, or diesel motor,
- A gear reducer connected to the motor by belts and equipped with a brake on the input pulley;
- A crank-slider mechanism to convert rotation into back-and-forth motion,
- A beam that balances the weight of the rods on one side and adjustable counterweights on the other to ensure smooth operation during the up and down movements,
- A headframe that holds everything together,
- A "horsehead" that holds the rod support cable [2].

Pumping units are identified by three key numbers

- The first number indicates the maximum torque at the reducer in thousands of inch-pounds,
- The second number represents the maximum load on the polished rod in hundreds of pounds.
- The third measurement, in inches, indicates the maximum travel of the polished rod.

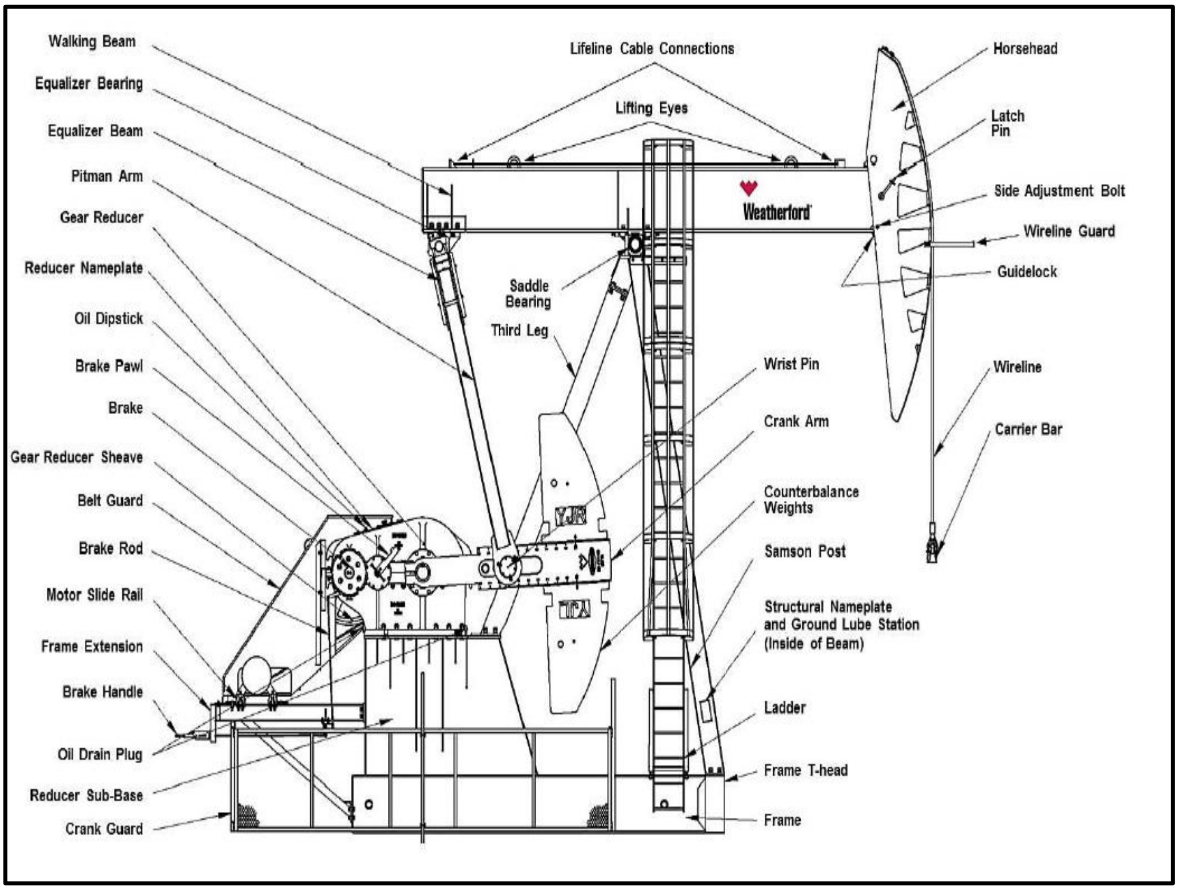


Figure 24: The Sucker Rod Pump unit [7].

2.3 Role and Adjustment of Counterweights

Counterweights, heavy masses positioned on the beam opposite the rods from the pivot point, play a crucial role in regulating the engine's operation.

$$CE = Pt + 0.5\ P_f$$

Where

CE: counterweight effect

Pt: combined weight of the rods in liquid

Pf: weight of fluid

In practice, these loads are dynamic rather than static. When calibrating the counterweights, an acceleration factor (impulse factor) linked to the stroke and speed must be considered. This factor alters the maximum and minimum loads on the polished rod. Adjustments to the counterweights are made based on precise calculations.

For optimal performance, it is recommended to fine-tune the counterweights on-site using a load diagram for the polished rod, obtained through dynamometric measurements during a complete pumping cycle [7].

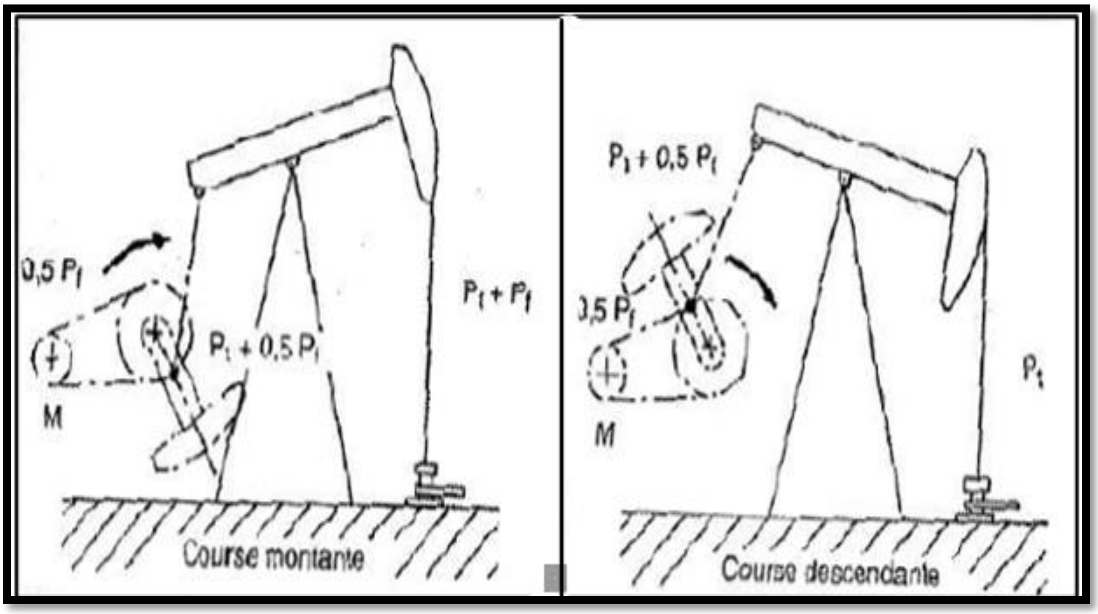
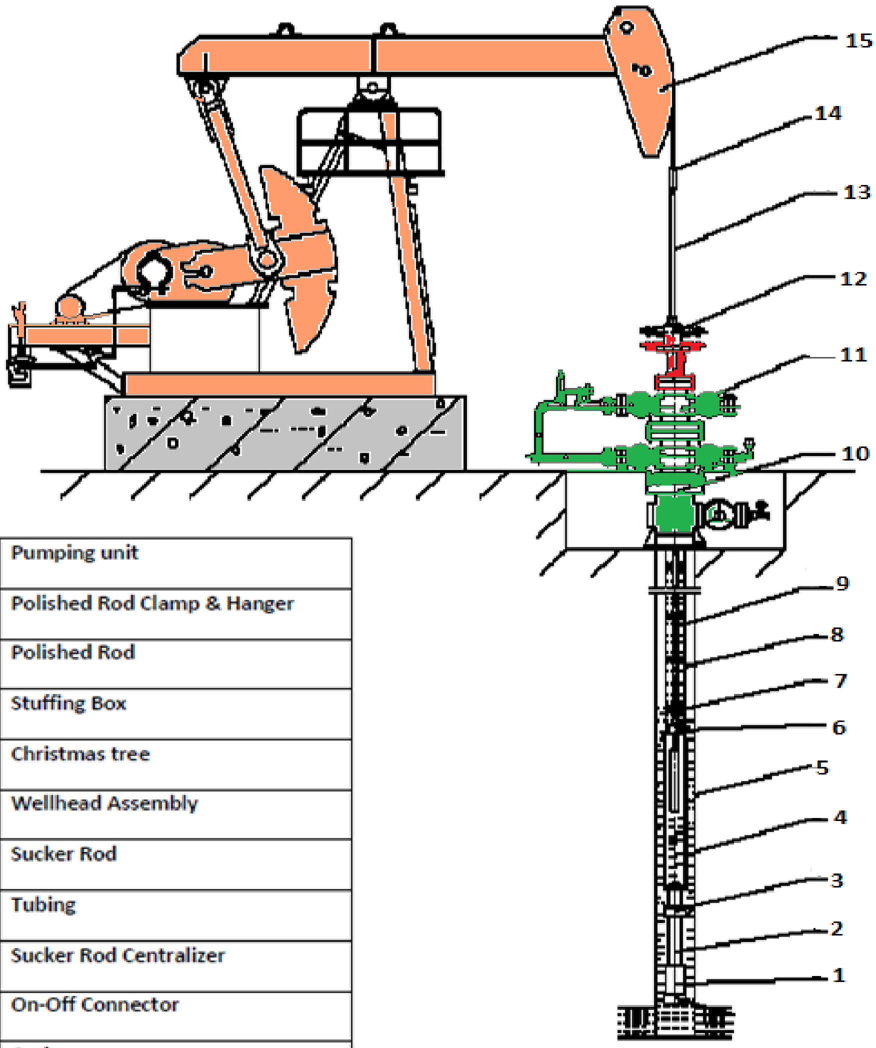


Figure 25: Charges supported at the pumping unit level [7].

the figure below shows the SRP System Field:



15	Pumping unit
14	Polished Rod Clamp & Hanger
13	Polished Rod
12	Stuffing Box
11	Christmas tree
10	Wellhead Assembly
9	Sucker Rod
8	Tubing
7	Sucker Rod Centralizer
6	On-Off Connector
5	Casing
4	Tubing Pump
3	Gas Anchor
2	Tail Pipe
1	Tube Coupling

Figure 26: Sucker Rod Pump System Field [2].

2.4 Pumping Parameters Selection

A. Pump Depth

The pump must be located below the "dynamic level" which depends on:

• The bottom hole flowing pressure (pf), with: $\mathbf{Pf} = \mathbf{P}g - \frac{\mathbf{Q}}{\mathbf{IP}}$

Where PG: Reservoir Pressure; psi

Q: Desired flow rate; STb/d

IP: Productivity Index; STb/d/psi

Q/IP: Δ PG = pressure losses in the reservoir and around the well;

• The average density of the produced effluent.

Note that the reservoir pressure (PG):

- Declines over time with cumulative production;
- Also allows determining the static level [7].

B. Flow-Related Parameters

The pumped flow rate essentially depends on the piston diameter, pump stroke, and pumping rate (or speed).

The same flow rate can be obtained for different combinations of these parameters. Among the ranges offered by manufacturers, the choice of the solution is made taking into account particularly the mechanical fatigue problems of the rods [7].

This is essentially a function of:

- The number of cycles (pumping rate);
- The difference between the maximum pull on the upstroke and the minimum pull on the downstroke;
- The maximum load compared to the yield limit [7].

C. Choosing The Right Pumping Speed

In practical terms, it's best to keep pumping speeds below twenty strokes per minute. Moreover, syncing the pumping speed with the natural vibration frequency of the rods or a harmonic of it can quickly lead to pump damage due to piston impact and even the snapping of the rod string. To steer clear of these risks, it's advisable to opt for an asynchronous pumping speed [7].

Irrespective of the pumping method used, especially in rod pumping scenarios, the initial steps, based on reservoir characteristics, involve:

- Selecting the desired flow rate;

- Determining the minimum pump depth required.

When it comes to the actual pump depth, it's recommended to avoid placing the pump significantly lower to reduce stress on the rods [7].

2.5 Setting Up a Rod Pumping System

The final configuration of a pumping system is reached through a series of progressive steps. The fundamental process can be broken down into three stages:

a) Initially, key operational parameters and system components need to be identified, including:

- Liquid level;
- Pump depth, and Pumping rate;
- Surface stroke (polished rod stroke);
- Pump and piston diameter;
- Fluid density;
- Tubing diameter;
- Anchored or free tubing status;

The composition of the pumping train (rod diameter).

b) From there and with an appropriate method, we seek to determine the corresponding operating parameters and in particular:

For the bottomhole equipment:

- The piston stroke;
- The volume effectively pumped;
- The maximum load on the polished rod;
- The minimum load on the polished rod;

For the surface unit:

- The maximum torque at the gearbox;
- The power required for the polished rod;
- The required counterweight;
- The power of the motor to be installed on the unit [7].

3. Electrical Submersible Pump

The Electric Submersible Pump is the most competent and consistent method of artificial lift when moderate to high volume of oil needs to be lifted from the well. He also estimated the lifting capacity of ESPs to be as low as 150 barrels per day and as high as 150,000 barrels per day. The ESP system includes a multistage centrifugal pump, bolt-on intake, a seal-chamber section (protector), and a motor with sensor. The remaining components are the surface control panel and the power cable running from the surface downhole to the motor. According to Takacs, ESPs have shown an efficiency and consistency in lifting high volume liquid rates on and offshore. He clarified that the production through ESPs represents 10% of the world's oil supply [2].

3.1 Electrical Submersible Pump Systems

Centrilift electrical submersible pumping (ESP) systems mare state-of-the-art multiple stage centrifugal pumps. The Centrilift product range is built for durability and reliability in a wide range of applications ranging from slim-hole oil wells to very high production water wells to harsh environments and coal bed methane applications. When production rates reduce the down-hole pressure below the level required to bring fluids to the surface, the reservoir pressure must be supplemented with artificial lift. ESPs require a minimum amount of pressure at the intake. Since ESPs rely on pressure differentials for fluids to enter the pump, ESPs cannot pump the intake pressure to zero. Since ESPs can pump the pressure down to significantly lower levels, they are considered an effective and economical means of lifting well fluids. Over the years Centrilift, in partnership with major oil companies, has designed, engineered, and manufactured ESP technology that lasts longer and pumps more fluids. Centrilift's ESP systems perform in previously impossible well conditions, producing well fluids in even the following extreme environments:

- High Temperatures
- High Gas
- High Viscosity
- Abrasive& Corrosives
- Highly Deviated/Horizontal Wells [9].

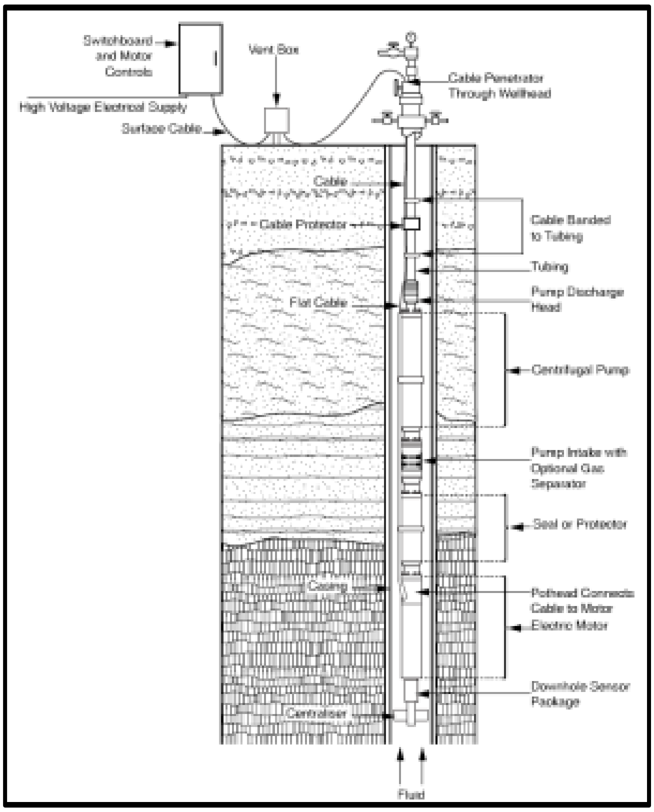


Figure 27: ESP systems [9].

3.2 Electrical Submersible Pump Components and Their Operational Features

An ESP system can be divided into two categories:

A. **Surface components**

f) **Transformer**

Transformer system is used to step-up or step-down the voltage from the primary line to the motor of the submersible pump. Because a range of operating voltages may be used for submersible pump motors, the transformer must be compatible with the selection of the motor voltage [9].

Figure 28: Typical Transformers [9]

g) Junction Box

A junction box (vent box) performs three functions. First, it provides a point to connect the power cable from the controller to power cable from the well. Second, it provides a vent to the atmosphere for gas that might migrate up the submersible power cable [9].

Finally, it allows for easily accessible test points for electrical checks of downhole equipment [9].

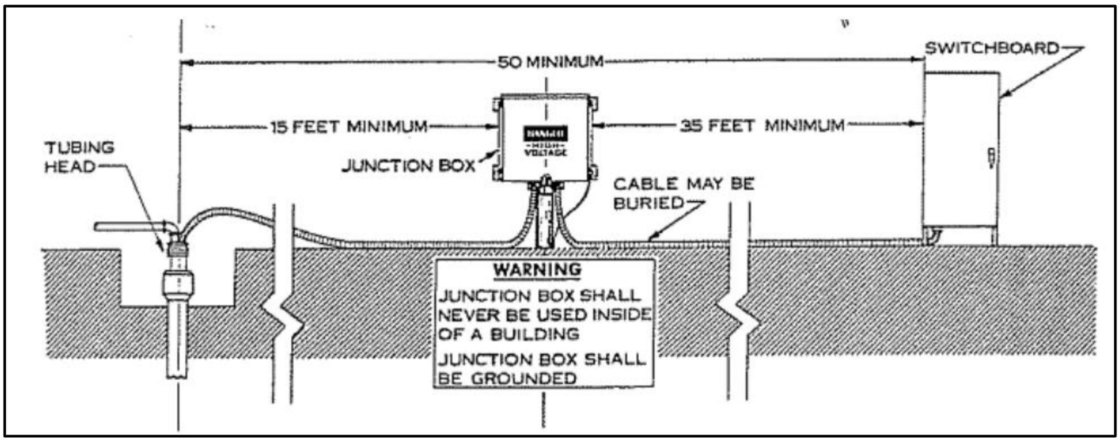


Figure 29: Typical junction box connection [9]

h) Switchboard

The switchboard controls the pump motor and provides overload and underload protection. Protection against overload is needed to keep the motor windings from burning. Protection during underload is needed because low fluid flow rates will prevent adequate cooling of the motor [9].

Figure 30: Typical switchboard [9].

i) Wellhead

The wellhead supports the weight of the subsurface equipment and maintains surface annular pressure of the well. It must be equipped with a tubing head bonnet or pack-off to provide a positive seal around the cable and the tubing (or feed though mandrel). There are several pack-offs available from wellhead manufacturers. The highest rated pack-off can sustain annular pressures up to 5,000 psi [9].

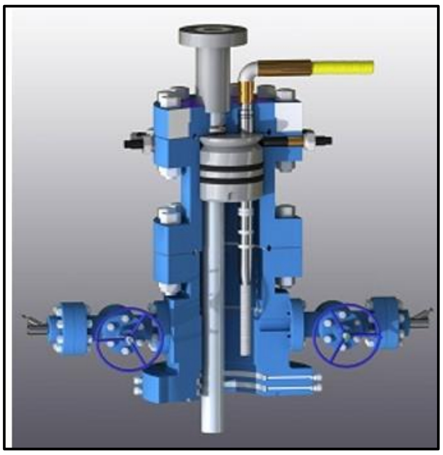


Figure 31: The wellhead [2].

B. Subsurface components

j) Check Valve

A check valve is installed about two to three joints above the ESP pump to maintain a full liquid column in the tubing string during equipment shut down periods. It prevents leaking of the fluid from the tubing down through the pump when the pump is not running [2].

Figure 32: Check Valve [2].

k) Drain Valve

When a check valve is used, it is recommended to install a drain valve to prevent pulling a wet tubing string. The drain valve is installed above the check valve. A drain valve installed alone is unnecessary as the fluid in the tubing will drain through the pump while pulling [9].

l) Pump

Centrilift ESP System Pumps are multi-stage centrifugal pumps that convert the energy from the rotating shaft into centrifugal forces that lift well fluids to surface. The pump is normally attached to, or hangs from the production tubing.

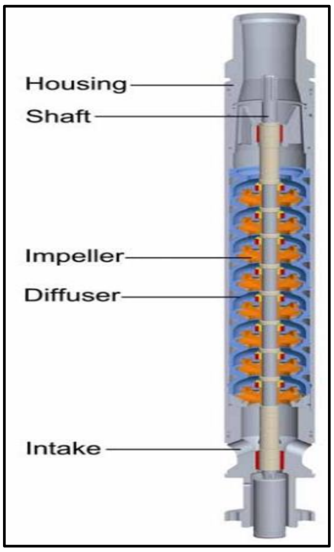


Figure 33: ESP Pump Cutaway [9].

• Impeller: The impeller is keyed to the shaft and rotates at the motor RPM. As the impeller rotates it imparts centrifugal force on the production fluid [9].

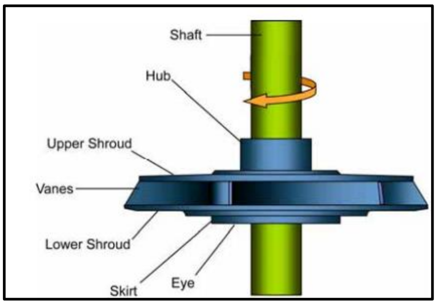


Figure 34: Illustration of Impeller and Sub-Components [2].

• Diffuser: The diffuser turns the fluid into the next impeller and does not rotate [9].

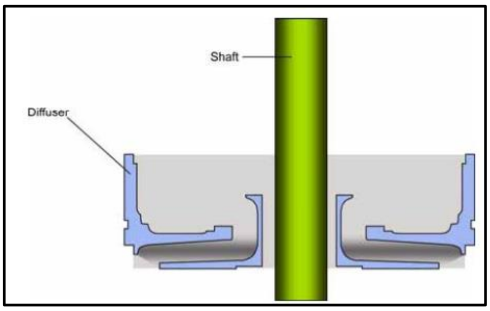


Figure 35: Illustration Cut-Away of a Diffuser [9].

• Pump Stage: A pump stage is formed by combining an impeller and a diffuser.

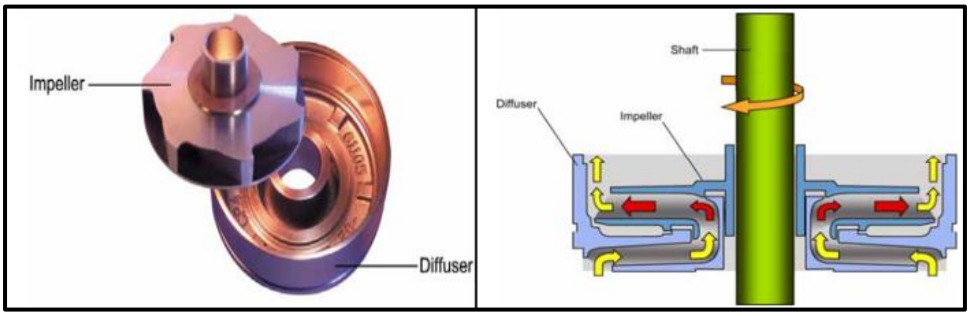


Figure 36: Illustration of a Pump Stage (Impeller and Diffuser) [9].

• Shaft: The pump shaft is connected to the motor (through the gas separator and seal section), and spins with the RPM of the motor [9].

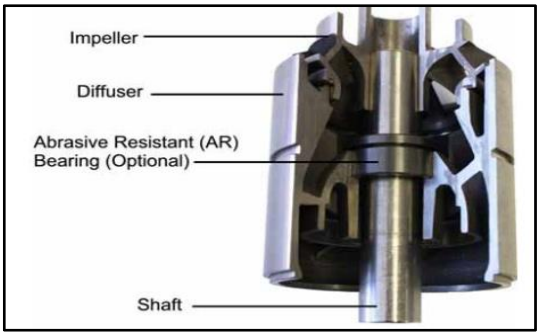


Figure 37: Shaft and Pump Stage Cutaway [2].

• Intake: The pump intake attaches to the lower end of the pump housing and provides a passageway for fluids to enter and a flange to attach to the ESP seal [9].

Figure 38: Pump Intake [9].

m) Gas Separator

In wells with high gas-oil ratio 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 eliminate gas locking and extend the application range of ESP systems [9].

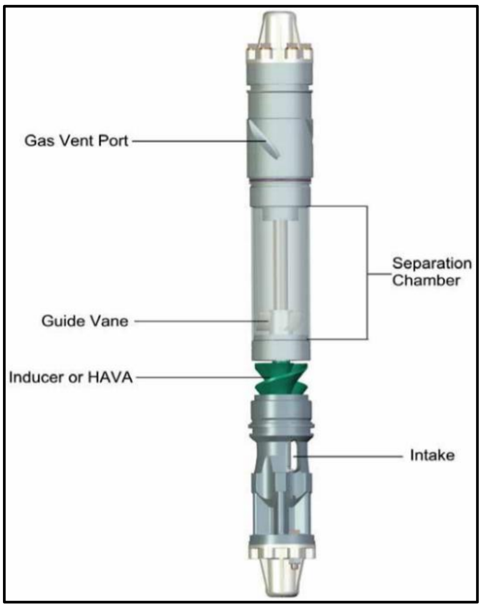


Figure 39: Rotary Gas Separator [9]

n) Seal

The seal section connects the motor shaft to the pump intake or gas separator shaft. Seal Sections also perform the following vital functions:

• Provides an area for the expansion of unit's motor oil volume

• Equalizes the internal unit pressure with the wellbore annulus pressure

• Isolates the clean motor oil from well bore fluids to prevent contamination

• Supports the pump shaft thrust load [9].

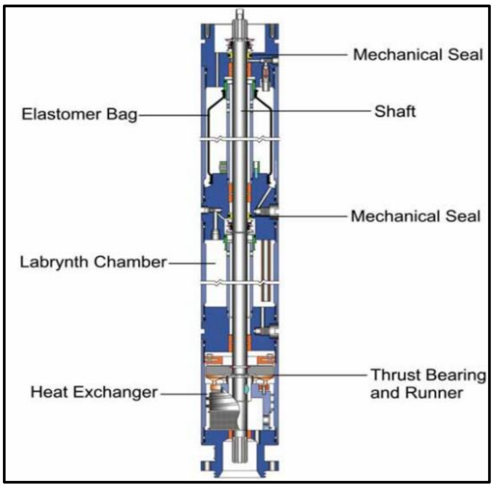


Figure 41: ESP Seal Components [9].

o) Motor

The main purpose of a motor is to convert electrical energy into motion that turns the shaft. The shaft is connected through the seal and gas separator and turns the pump impellers [9].

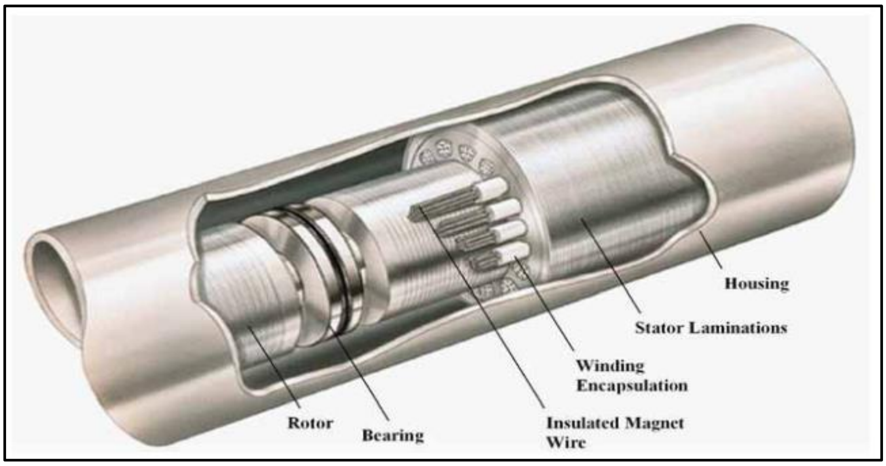


Figure 42: ESP Motor Cutaway Illustration [9]

p) ESP Cable

- ESP Power Cable

Centrilift ESP cable is the critical link between the down-hole equipment and the power source. Power is transmitted to the submersible motor by banding a specially constructed three phase ESP electric power cable to the production tubing. This cable must be of rugged construction to prevent mechanical damage, and able to retain its physical and electrical properties when exposed to hot liquids and gasses in oil wells [2].

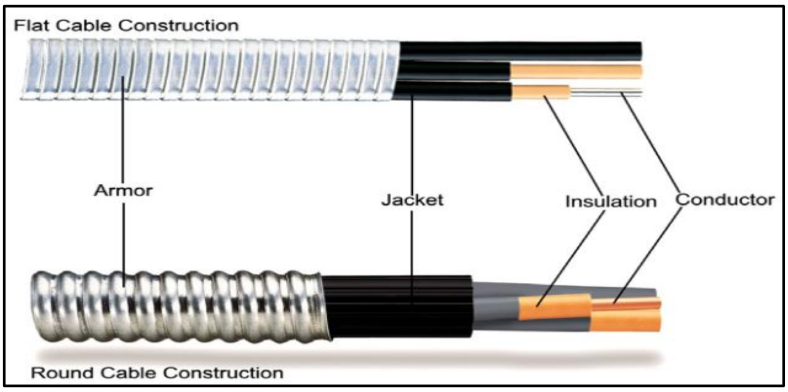


Figure 43: Flat and Round Cable Cutaway [9].

Centrilift cables are constructed in both round and flat configurations. Most cable are composed of at least four components; a conductor, insulation, jacket and armor [2].

3.3 Electrical Submersible Pump Installations

There are two types of installations; tubing-deployed and alternative deployed systems. In the first type, the ESP will be attached at the end of the production tubing, whereas the second type uses either ESP cable or Coiled Tubing (CT) deployment [10].

3.3.1 Tubing Deployed Installations

This type of installation uses the production tubing to deploy and retrieve ESPs. Depending on the production strategy (i.e., producing from single zone or dual zone), different installation techniques are available.

Producing From Single Zone

In horizontal wells, the installation techniques of ESPs follow special criteria. The set point of ESPs in horizontal wells is usually above the kickoff point in the vertical section of the well. Sevin pointed out that ESPs can be set in the horizontal section if the casing size is large enough and accessibility of that section is possible. Moreover, Duffy et al. suggested that two ESP systems can be installed in parallel for several applications. One of these applications is an offshore installation. The cost of the workover will be reduced since the failure of one ESP doesn't require a replacement because the other ESP will take over to compensate for the loss in production [10].

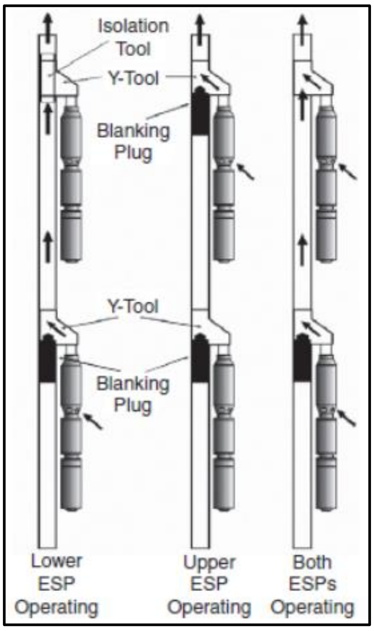


Figure 44: Parallel connection
of two ESPs [10].

Fig.44 shows the two ESPs connected in parallel and attached to the tubing through a Y-tool. This Y-tool helps to access wellbore and select between the two systems. As shown in the left-hand part of Fig. 15, the lower ESP is desired, so a blanking plug is installed in the Y-tool to prevent flow circulation where the isolation tool is set in the Y-tool of the upper unit. The Fig45 shows the mechanism when the upper ESP is in operation. A blanking plug will be set in the upper Y-tool instead of the isolation tool. This blanking plug will help in preventing any fluid circulation. In case both units are in operation, as shown in the right-hand. a blanking plug will be set only in the lower Y-tool. The parallel installation can sometimes be useful where we have restrictions in surface or downhole. The operation of both units as the same time can increase the well's production for the same total dynamic head. Moreover, a failure of one ESP will not cause a loss in production because the other unit will compensate for the production of the failed ESP [10].

Installing two units in series can provide a booster-pump setup. This also increases the lifting depth while the production rate is the same. Also, for the same total dynamic head, it can increase the total liquid rate. Series-connected installations are usually utilized when no motor is available for a given size of casing. This is due to the great lifting depth or high production rate. Also, the inflow rate of the wells is decreasing sharply, and ESP capacity has to be reduced after the initial production and if there is a possibility of a collapse to the casing due to high pressure drawdown caused by producing more to meet target [10].

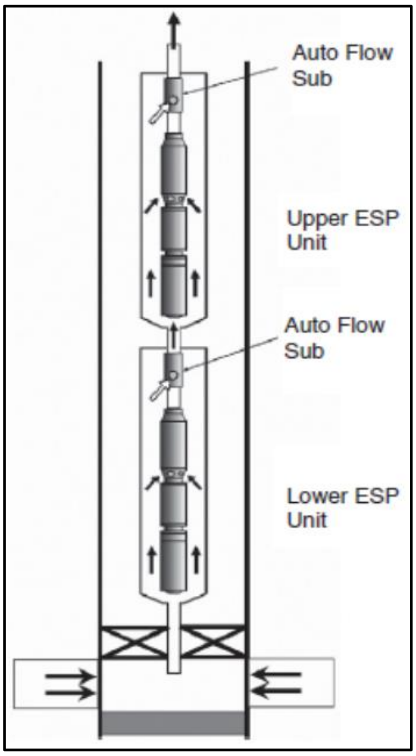


Figure 45: Series connection of two ESPs [10].

3.3.2 Alternative Deployed Installations

One of the big incentives of using the alternative deployed installation rather than the tubing-deployed installations is that the tubing-deployed installation requires high-capacity workover units that are costly and not always available to run and retrieve tubing and ESP. However, running and retrieving ESP on its electrical cable or on a CT (Coiled Tubing) string eliminates the use of the heavy tubing string and requires workover rigs of much smaller load capacity and service fee; operational costs are therefore effectively reduced [10].

a) Cable Suspended ESPs

ARUTUNOFF and O'ROURKE introduced the concept of running ESPs on their electrical cable back in 1970 [10].

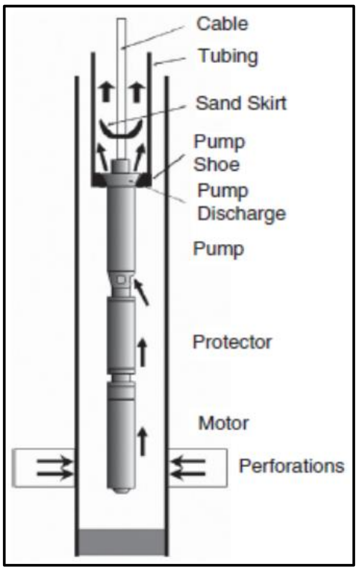


Figure 46: typical cable suspended ESP [10].

In this type, typically the ESP is run at the end of an electrical and reinforced cable that can withstand the weight of the pump. The ESP is set at the tubing shoe inside the tubing. This tubing shoe will help in supporting the weight of the ESP and will act as a seal between the suction and discharge points of the ESP during production, and the flow will go through the intake to the tubing and all the way to the surface. The sand skirt that is installed above the cable connector will help in preventing sand accumulation above the discharge point when the pump switches off. This type of installation is limited to shallow wells since cable strength will decrease with depth causing a failure of cable to handle the ESP [10].

b) Coiled Tubing (CT) Installations

The method of installing ESPs by their cables showed that it is not the best or the most effective way to install such pumps. This is due to the special tools and handling to the high strength cables, the complicated cable splicing (because of the dual function of the cable: load and electricity carrying), and the high costs associated with cable manufacture. The best solution is to install ESPs by CT [10].

The first CT installation was done back in 1992. The ESP was run and installed by CT rather than installing by tubing string. Hence, the workover cost was reduced significantly [10].

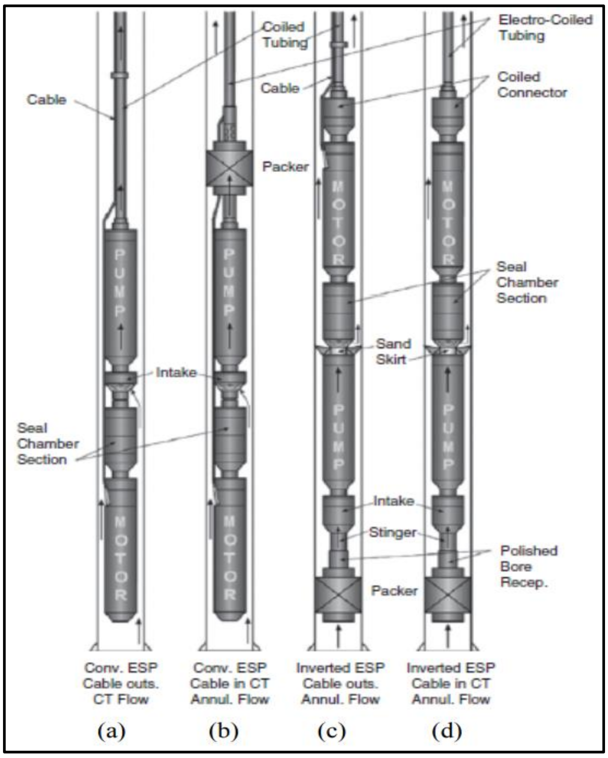


Figure 47: Coiled tubing ESP installation [10].

- **Conventional Installation with Cable Led Outside CT String**

As seen in Fig. 47 (a), the installation is the same as the conventional way with the difference of using CT string rather than joint tubing string. This version requires only CT injector and avoids utilizing high-capacity workover unit to retrieve and run tubing string. However, there are many disadvantages with regard to this version. These disadvantages include:

- The small CT string size will cause high frictional pressure loss that requires high motor power.
- The production of the well might be limited by the smaller size of CT string.
- CT and ESP must be spooled during workover operations.
- Running/pulling speeds are limited because of the need to band the cable to the CT string [10].

- **Conventional Installation with Cable Led Inside CT String**

In Fig.45(b), the flow will go through the annulus to the surface. This technique will help in reducing friction losses and increasing the capacity of the production. The packer above the pump is used to divert fluid into annulus. In case of associated gas production, the free gas can be collected below the packer and vented through a sliding sleeve or vent valve. If more gas production is encountered/expected, a special pump that can handle a large volume of gas is installed. Advantages of this technique are summarized below:

- The cable inside the CT will be secured against any physical or mechanical damage.
- Since cable banding is not required inside CT, the maximum speed of pulling and running of CT can be used.
- Due to the possibility of the sealing around CT, running/retrieving of ESP can be done under pressure.
- Killing operation can be avoided because of the ability of running/retrieving ESP under pressure.
- Conventional ESP equipment is typically installed in this type [10].

➢ **Inverted ESP Units**

In this type of installation, the setup is inverted; i.e., the electric motor is at the top and the pump at the bottom. The cable is connected directly to the motor without the use of MLE (motor lead extension). The MLE is a vulnerable flat cable usually running to the pothead on the motor. The centrifugal pump is modified so that the discharge point directs fluid to the annulus. The suction and discharge head are isolated by either packer or PBR (polish bore receptacle) as shown in Fig. 45 (c) & (d). The sand skirts are used to collect sand above the packer and around the ESP when the unit is down. In this installation, the cable can be either clamped outside or inside the CT. Many manufactures had improved this technique by fabricating different CT sizes with integrated ESP cables [10].

4. Nodal Analyses

4.1 PIPESIM Software Presentation

The PIPESIM software is a simulator designed by the service company Schlumberger. It allows us to analyze the performance of producing or injecting wells based on the description of the effluent flow process from the reservoir to the surface separator. This simulator offers a variety of specific well simulation tasks, addressing a wide range of well modeling workflows [8].

- **Such a flow process is subdivided into three phases, namely**

- Flow at the bottom (through the reservoir)

- Flow through the completion (liner, tubing, annular space, etc.)

- Surface flow (through the gathering network, separator, etc.)

- **Data required for the use of PIPESIM**

- Completion data (well technical sheet, monitored data, etc.)

- Petrophysical data

- Geological report

- PVT data (Bubble pressure, Oil and gas density, Fluid viscosity, etc.)

- DST, Build up, Gauging test data, etc. [8]

4.2 Understanding Pressure Losses Analysis

The system responsible for fluid transport can be broken down into three main sections:

a) . Flow in porous medium

b) . Flow in vertical or directional pipes

c) . Flow in horizontal pipes

The overall pressure drop in the system equals the difference between reservoir pressure and separation pressure: $\Delta p_{totale} = \bar{p}_R - p_{sep}$,

Where; $\bar{p}_R$ and p_{sep} represent the average reservoir pressure and separation pressure respectively.

This pressure drop encompasses the cumulative losses across various system components. While selecting and sizing these components is crucial, their interplay means a change in one can impact fluid behavior in others.

Hence, it's essential to analyze the production system (reservoir + well + surface collections) as a unified entity. Isolating individual parts doesn't yield optimal outcomes. Often, a well's production is constrained by a single component's performance. By pinpointing each component's influence on system performance, optimization can be achieved economically [8].

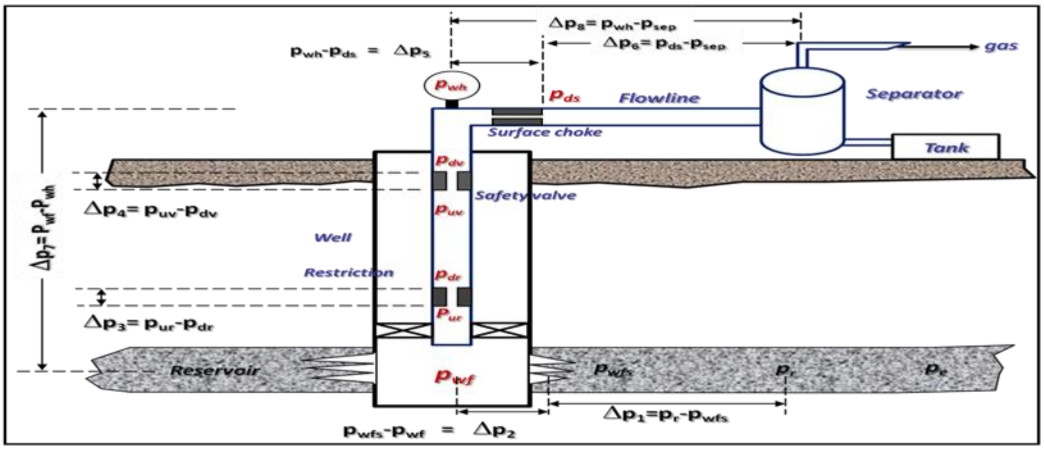


Figure 48: the diverse pressure losses within the production system [8].

Refer to Figure (46) for a visual representation of the diverse pressure losses within the production system.

- Δp1 = pR - pwfs: Losses within the porous medium;
- Δp2 = pwfs - pwf: Losses through completion (perforations);
- ΔP3 = pur - pdr: Losses through restrictions;
- ΔP4 = Pusv - Pdsv: Losses via the safety valve;
- ΔP5 = Pwh - Pdsc: Losses across the surface nozzle;
- ΔP6 = Pdsc - PSep: Losses in surface pipelines;
- ΔP7 = Pwf - Pwh: Total losses in the tubing;
- ΔP8 = PWH - Psep: Overall losses in collections [8].

4.3 Nodal Analysis Principle

The concept of system analysis known as "NODAL ANALYSIS" has been used for many years to evaluate the performance of systems consisting of multiple units that interact with each other. This method is applied to electrical circuits, complex pipeline systems, and centrifugal pumping systems [8].

The first application of this method on oil-producing wells was introduced by Gilbert in 1954 and later discussed by NIND in 1964 and Brown in 1978. The procedure involves selecting a division point or node in the system and splitting it into two parts: the upstream and downstream sections. The most commonly used nodes are illustrated in the following figure:

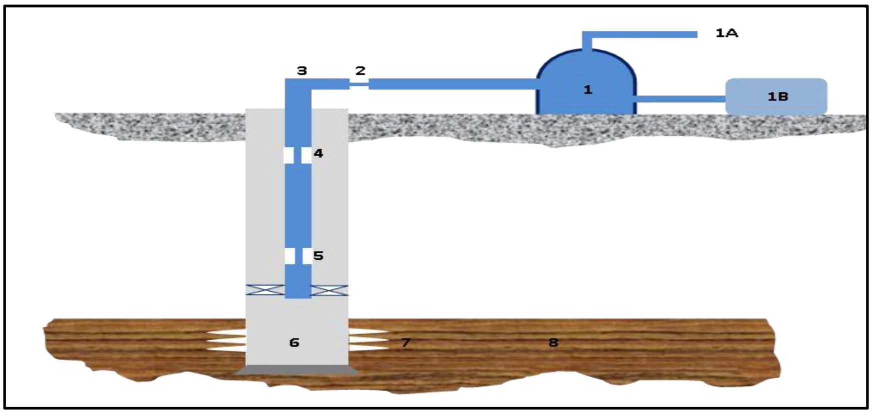


Figure 49: different location of nodes [8].

All components located before the chosen node are referred to as the Inflow section, while the Outflow section includes all components situated after this node. The flow rate of the effluent circulating in the system can be determined when the following conditions are met:

- The inflow at the node equals the outflow
- Only one pressure can exist at a node [8].

During the operation of the well, there are two pressures that remain constant and do not depend on the flow rate. One is the average reservoir pressure $\bar{p}_R$, the other is generally the separation pressure $p_{sép}$ (or the wellhead pressure p_wh if the well is controlled by a surface choke). Once the node is chosen, the pressure at that node is calculated from the two directions (upstream and downstream) starting from the fixed pressures ($\bar{p}_R$ et $p_{sép}$):

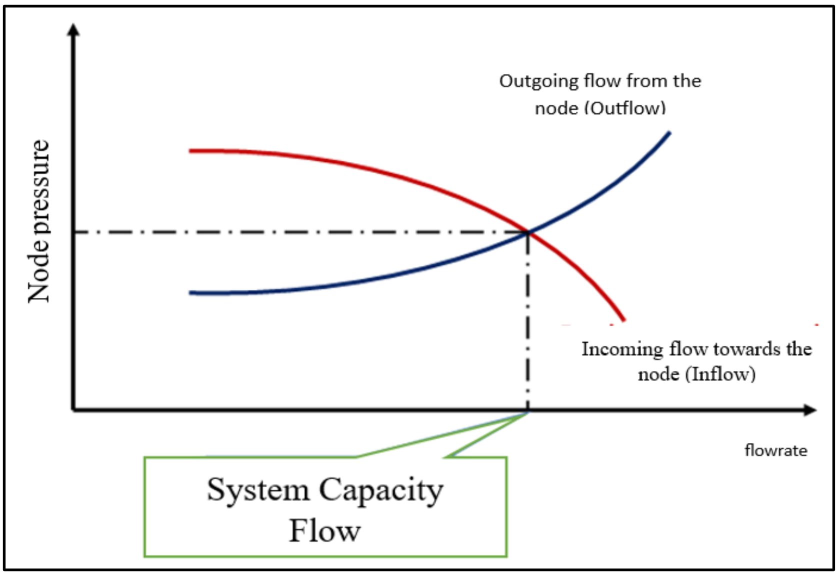


Figure 50: Flow Capacity Determination [8].

- Incoming flow towards the node (Inflow): $\bar{p}\bar{p}_R - \Delta p_{(amont)} = p_{noeud}$
- Outgoing flow from the node (Outflow): $p_{sep} + \Delta p_{(aval)} = p_{noeud}$

The pressure losses ΔP in the various components depend on the flow rate. As a result, when graphing the node pressure against the flow rate, two curves emerge, and their intersection represents the system's operating point that meets the two aforementioned requirements. This process is depicted in Figure II-03. Analyzing the impact of changes in the different components involves recalculating the node pressure based on the flow rate for the new characteristics of the same [8].

Each component. If a change is made in one of the upstream components, only the Inflow curve changes (the Outflow curve remains the same). However, if one of the downstream components is modified, the Outflow curve changes and the Inflow curve remains the same. If either of the curves is modified, their intersection will be shifted and new pressure and flow conditions will occur at the chosen node. The shift of the two curves can also occur in the case where fixed pressures ($\bar{p}_R$and $p_{sép}$) or one of them undergoes a change (reservoir depletion or separation pressure change) [8].

a) Application Process

A general procedure for solving most cases involves the following steps:

- Set a specific objective for the case, such as determining the tubing diameter to be used in a well.

- Determine the type of analysis required to solve the problem, such as analysis systems.
- Determine the required components (reservoir, well, completion, and flow plan), and the desired correlations.
- Calculate the case and verify the performance graphically.
- Interpret the performance based on the type of case. Examine the results by comparing the findings to the input data.
- Adjust the input and recalculate to improve the performance results as necessary.
- Repeat steps 1-6 for the next case objective [2].

b) The different positions of the node

A. Node 1the separator

The choice of the node at the separator level allows the study of the effect of the separator pressure on the well operation.

The necessary data are:

• IPR measured in the wellbore.

• Pressure drops in the tubing as a function of flow rate.

• Pressure drops in the gathering as a function of flow rate.

B. Node 3 the wellhead

The choice of the node at the wellhead level allows studying the effect of the collection diameter on well performance. The necessary data are:

• IPR (Inflow-Performance-Relationship) measured in the well

• Pressure drops in the tubing as a function of flow rate

• Pressure drops in the collection as a function of flow rate

• Separator pressure

C. Node 6 the bottom hole

Choosing the node at the bottom hole allows us to study the effect of the IPR (node at the bottom of the well) and the tubing diameter on well performance. The necessary data are:

• The IPR curve measured in the wellbore

• Pressure drops in the tubing as a function of flow rate

• Pressure drops in the collection as a function of flow rate

• Separator pressure (separation)

D. Node 8 the reservoir

The choice of the node in the reservoir allows us to understand the effect of reservoir depletion on well performance. The necessary data are:

- IPR measured in the wellbore.

- Pressure drop in the tubing as a function of flow rate.

- Pressure drop in the gathering system as a function of flow rate.

- Separator pressure (separation).

E. Node 2 the nozzle

The location of node 2 (nozzle) allows us to study the effect of the nozzle and control the production flow rate. The necessary data are:

- IPR measured in the wellbore.

- Pressure drop as a function of flow rate.

- The equation $p_{wf} = f(GLR, q)$

q: Production flow rate.

F. Node 7 Perforation Level

Studying the impact of perforation density in a well is made possible by focusing on the node at the perforation level. To conduct this analysis, the following data is required:

- Initial Production Rate (IPR) of the formation pre-perforation.

- Pressure drop in the tubing relative to flow rate.

- Pressure drop in the collection system.

- Separator pressure readings [8].

4.4 Applications of Nodal Analysis

Nodal analysis proves to be a versatile tool for troubleshooting various issues encountered in oil and gas wells. It can be applied to both gushing and activated wells, as well as water or gas injection sites by adjusting Inflow and Outflow parameters. Some potential applications include:

1. Selecting optimal tubing dimensions.
2. Choosing the right surface collection setup.
3. Designing an effective Gravel Pack.
4. Determining the ideal nozzle diameter.
5. Sizing the sub-surface safety valve correctly.
6. Investigating abnormal flow restrictions in existing systems.
7. Designing gas-lift and pumping mechanisms.
8. Evaluating well stimulation techniques.
9. Assessing compression effects in gas wells.
10. Analyzing the impact of perforation density.
11. Predicting production capacity changes due to reservoir depletion [2].

4.5 Well Modeling Process

This model is used to create well models before incorporating them into the network model. The steps involved in creating a well model in the software include:

- Selecting the unit set for performance evaluation.

- Identifying the completion type: multiple, horizontal, single.

- Adding modeling components (completion, tubing...) and required data.

- Defining fluid specifics (PVT data).

- Choosing the flow correlation.

- Plotting the inflow and outflow curves.

- Saving the model.

By leveraging data from various departments within the EP structure, we have gathered all essential information. To achieve the desired outcomes, we follow the approach outlined in Fig 49 [2].

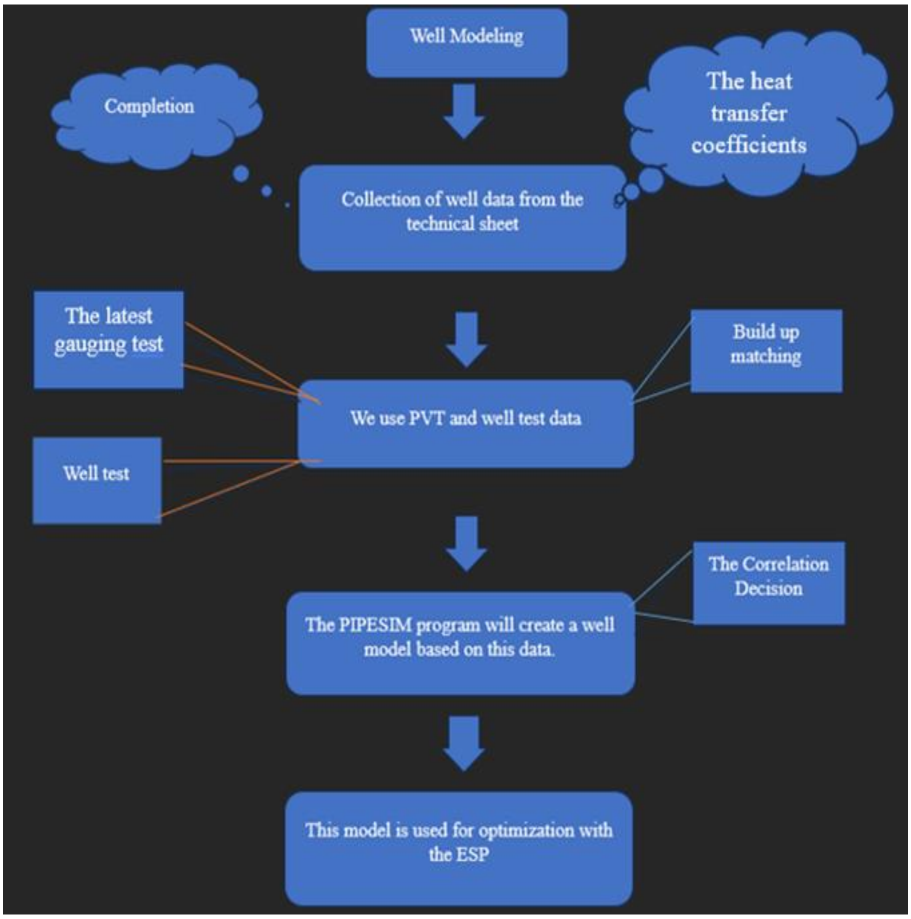


Figure 51: Steps for Wells Modeling

Chapter IV: Case Study

Introduction

The GASSI TOUIL region, a hub of hydrocarbon production, is home to two primary processing stations. The older station is dedicated to crude oil treatment and encompasses two main units:

1. **Separation Unit**

   This unit is responsible for the purification of crude oil by removing associated gas, water, and sediment, ensuring the oil meets the required cleanliness standards.

2. **Gas Collection and Compression Unit**

   The gas extracted during the separation process is compressed and subsequently reinjected into the reservoir. This technique is employed to maintain the pressure within the reservoir, which is crucial for optimal extraction rates.

Conversely, the newer station has been engineered to handle a substantial throughput of 12 million cubic meters of gas per day, sourced from the prolific fields of HASSI TOUARG, GASSI TOUIL, ROUD ELKHALEF, NEZLA, TOUAL, and Brides. This facility primarily serves the recompression stations.

The Central Processing Facility (CPF) operates within a capacity range of 30% to 110% of its base capacity, translating to 3.6 million to 13.2 million cubic meters of gas per day. Additionally, the CPF contributes to the production of Liquefied Petroleum Gas (LPG) and condensate, adding value to the overall output.

Geographically, the Gassi Touil field is situated approximately 150 km southeast of Hassi Messaoud and 1000 km from Algiers. It is strategically located along the RN 3 national road, which connects Ouargla to IN AMÉNAS.

The region is segmented into multiple zones, each with its own discovery timeline and well count, as follows:

- GASSI TOUIL: Discovered in 1961, featuring 80 gas wells.
- NEZLA Nord: Unearthed in 1958, with 10 oil and gas wells.

- NEZLA Sud: Also discovered in 1958, housing 30 gas wells.
- HASSI TOUAREG: Identified in 1958, with 13 gas wells.
- HASSI CHERGUI: Discovered in 1962, with 10 oil wells.
- GASSI EL ADEM: Found in 1967, with 9 gas wells.
- BRIDES: Discovered in 1958, with 12 gas wells.
- TOUAL: Unearthed in 1958, comprising 32 gas and condensate wells.

1. Water and Gas Shutoff Technics

The GASSI TOUIL oil field encounters several problems and changes such as the decrease in oil productivity and the increase in GOR and water-cut which vary from one well to another; on the other hand, a single well can have multiple factors of different origins.

Four wells (GT03, GT30, and GT45) have been selected at the production field of GASSI TOUIL in the OUARGLA province, experiencing problems directly impacting their productivity. To identify breakthrough points as soon as possible, PLT (Production Logging Tool) campaigns are systematically conducted every year in the oil production wells. This part will examine both production logging operations, measurement results, and available options for contingency repairs.

1.1 Data Collection

• Data provided by the PLT records and generated by the Emeraude software (Production profiles of each well (Figures 49, 50 and 51), producing zones with their contributions, and damaged intervals...);

GT03 (PLT executed on 28/10/2021), GT30 (27/10/2021) and GT45(25/10/2021)

• Gauging data: measurement of oil flow rates (Qo), gas flow rates (Qg), Gas oil ratio (GOR), GT 03 (no-candidate for any solution), GT30 (Before the implementation of the solution:15/03/2023, After the implementation of the solution:07/11/2023), GT45 (Before:25/10/2021, After01/04/2022).

• Geological data: Depth, thickness, useful oil height ... etc.

Note: These data are taken from the SONATRACH company's data bank.

1.2 Well, GT03

This is an oil-producing well, it was drilled on Novembre 1962 in the GT oil zone. The well started production in April 1963 with an oil flow rate of 1400 m³/day, and a Gas-Oil Ratio (GOR) of 150.89 m³/m³. On 10/12/2019, the oil flow rate (Qo) became 10.3 m³/day, while the GOR was around 19293.49 m³/m³. Therefore, it appears that the well has been production since its drilled, as shown in the historical oil production curves.

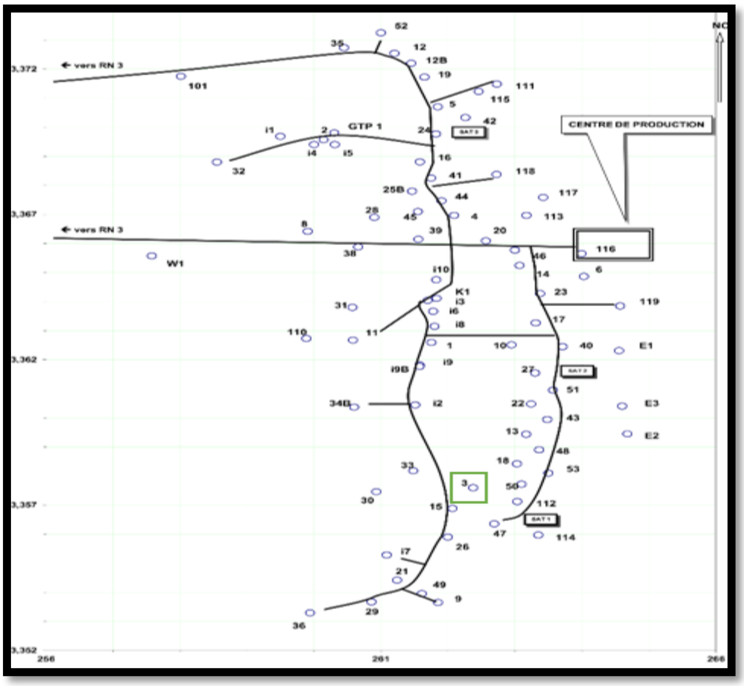


Figure 52: Locating well GT03 in the GASSI TOUIL field [2].

1.2.1 Presentation of the Well logging data Collection

To identify the breakthrough points of the PLT (Production Logging Tool) campaigns, surveys were carried out in the wells selected for this study (Fig. 53).

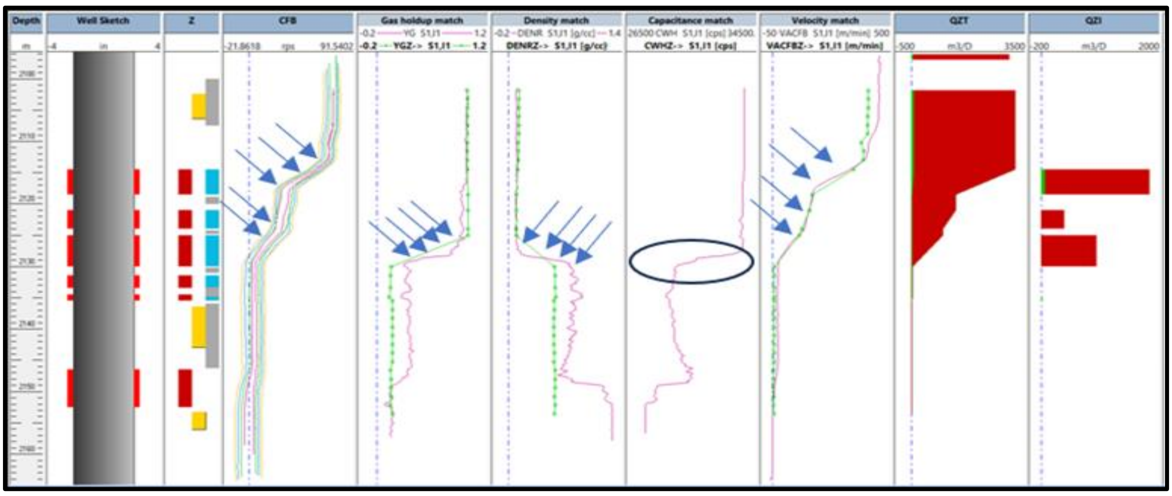


Figure 53: The production profile of the well-studied GT03 (according to the PLT conducted on 28/10/2021).

1.2.2 Results Discussion

A gas breakthrough is observed at well GT03 in the interval (2039m -2042m), (2043m -2045.5m), (2047m - 2051m), (2052.5m -2055m).

1.2.3 Solution Evaluation

Analyzing the PLT data revealed specific perforation intervals crucial for production

- Inflow Zone 2; 2039m-2045.5m: 97827 Sm^3/day of gas.

- Inflow Zone 1; 2047m – 2055m: 157821 Sm^3/day of gas, 11 Sm^3/day of oil.

Table 2: Contributions per phase of well GT03 generated by the Emeraude software.

Inflow Zones	Top perf	Bottom Perf	Calculated Gas Rate (Sm3/j)	Calculated Oil Rate (Sm3/j)
Zone 3 Squeezed Zones	2 021,0	2 023,5	-	-
	2 027,7	2 028,0		
	2 028,5	2 030,0		
	2 032,7	2 033,0		
Inflow Zone 2	2 039,0	2 042,0	97 827	-
	2 043,0	2 045,5		
Inflow Zone 1	2 047,0	2 051,0	157 821	11
	2 052,5	2 055,0		
Total			255 648	11

From the interpretation, it's evident that there is no water present in any production zones, with the majority of gas originating from inflow zone 1 (2047m – 2055m). The production profile suggests deactivating zone 1, which happens to be the oil-producing zone as well.

Consequently, well GT03 is deemed unsuitable for further operations.

1.3 Well, GT30

This is an oil-producing well, it was drilled in 1965 in the GT oil zone. The well started production in 1966 with an oil flow rate of 825 m³/day, and a Gas-Oil Ratio (GOR) of 163.64 m³/m³. On 10/03/2021, the oil flow rate (Qo) became 39,8 m³/day, while the GOR was around 5076.08 m³/m³. Therefore, it appears that the well has been drilled since its production, as shown in the historical oil production curves.

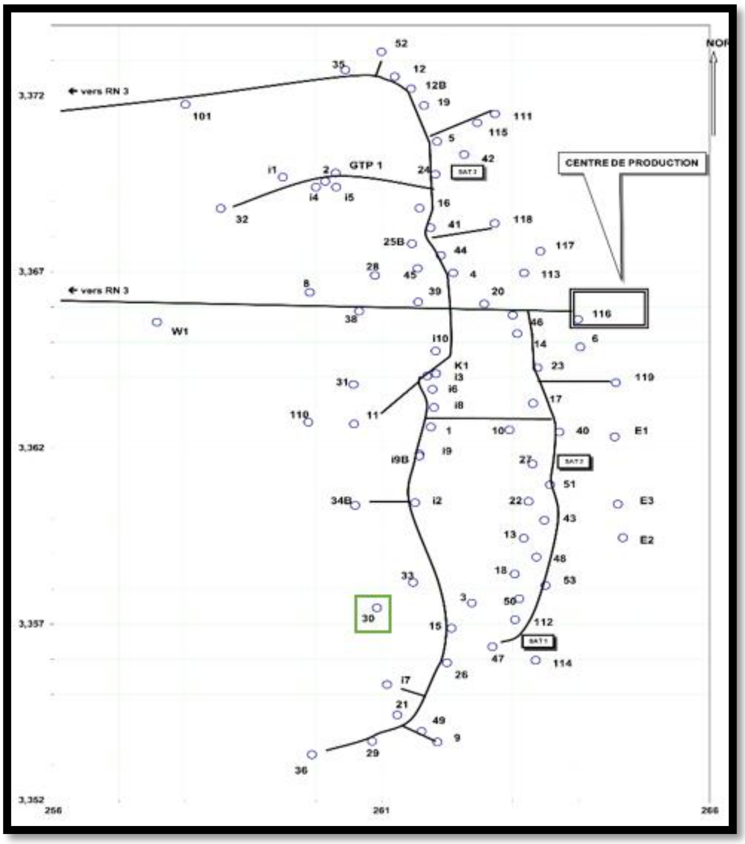


Figure 54: Locating well GT30 in the GASSI TOUIL field [2].

1.3.1 Presentation of the Well logging data Collection

To identify the breakthrough points of the PLT (Production Logging Tool) campaigns, surveys were carried out in the wells selected for this study (Fig. 55).

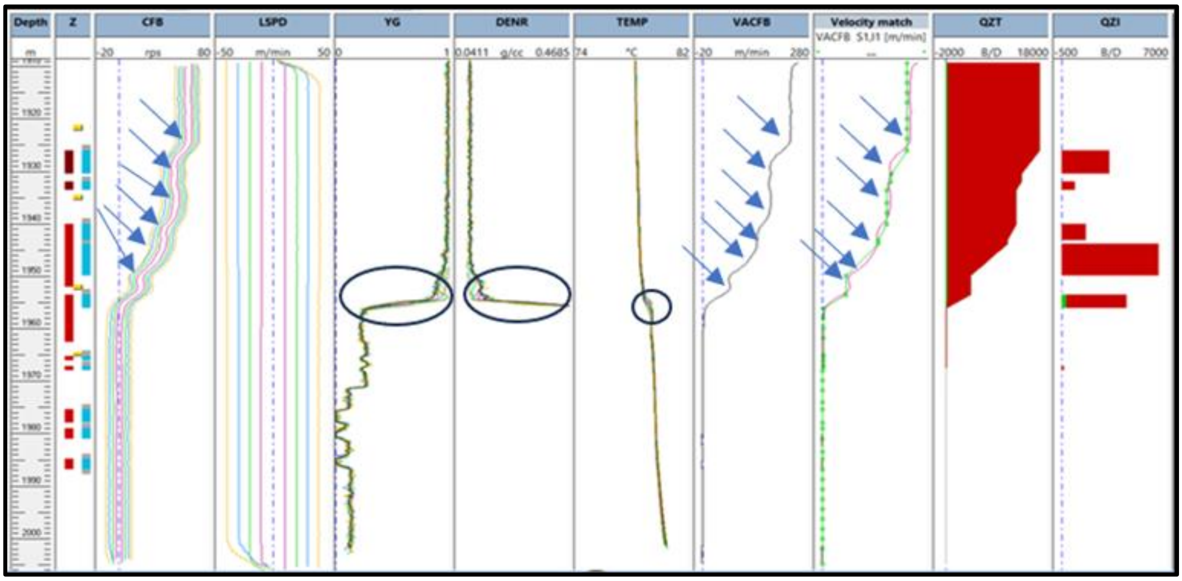


Figure 55: The production profile of the well-studied GT30 (according to the PLT conducted on 27/10/2021).

1.3.2 Results Discussion

A gas breakthrough is observed at well GT30 in the intervals (1926m -1930.5m), (1932m -1933.5m), (1940m - 1962m).

1.3.3 Solution Evaluation

Analyzing the PLT data revealed specific perforation intervals crucial for production

- Inflow Zone 3; (1926m – 1930.5m) / (1932m- 1933.5m): 63647 Sm^3/day of gas
- Inflow Zone 2; (1940m-1952m): 126126 Sm^3/day of gas.
- Inflow Zone 1; (1953.5m – 1962.5m): 68409 Sm^3/day of gas, 39 Sm^3/day of oil.

Table 3: Contributions per phase of well GT30 generated by the Emeraude software.

Inflow Zones	Top perf	Bottom Perf	Calculated Gas Rate (Sm3/j)	Calculated Oil Rate (Sm3/j)
Inflow Zone 3	1 926,0	1 930,5	63 647	-
	1 932,0	1 933,5		
Inflow Zone 2	1 940,0	1 952,0	126 126	-
Inflow Zone 1	1 953,5	1 962,5	68 409	39
No flow is Observed	1 965,2	1 966,0	-	-
	1 967,2	1 968,0		
	1 975,4	1 977,9		
	1 979,0	1 981,0		
	1 984,8	1 986,8		
Total			258 182	39

From the interpretation, it's evident that there is no water present in any production zones, with the majority of gas originating from the inflow zone 2 (1940m-1952m) and the inflow zone 3 (1926m – 1930.5m) / (1932m- 1933.5m). The production profile suggests deactivating the inflow zones 2&3. So, the Reducing of gas breakthrough will be done with isolating the gas-producing perforations between two packers.

The figure below shows the results of the gauge tests that were carried out for the evaluation.

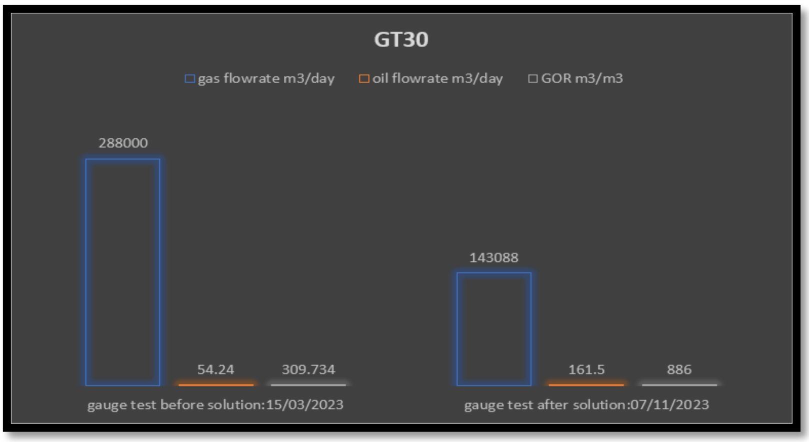


Figure 56: Comparison of the data from gauging test of well GT30.

Before the packer setting, it is noted that the GOR value is very high, reaching approximately 5309.73 m³/m³. This explains the low oil flow rate compared to gas. After the packer setting, the oil flow rate increased to 161.5 m³/day, while the gas flow rate decreased to 141088 m³/day, and the GOR level decreased.

1.4 Well, GT45

This is an oil-producing well, it was drilled in 1970 in the GT oil zone. The well started production on June 1971 with an oil flow rate of 750 m³/day, and a Gas-Oil Ratio (GOR) of 125.06 m³/m³. On 18/05/2011, the oil flow rate (Qo) became 6 m³/day, while the GOR was around 43919.17 m³/m³. Therefore, it appears that the well has been drilled since its production, as shown in the historical oil production curves.

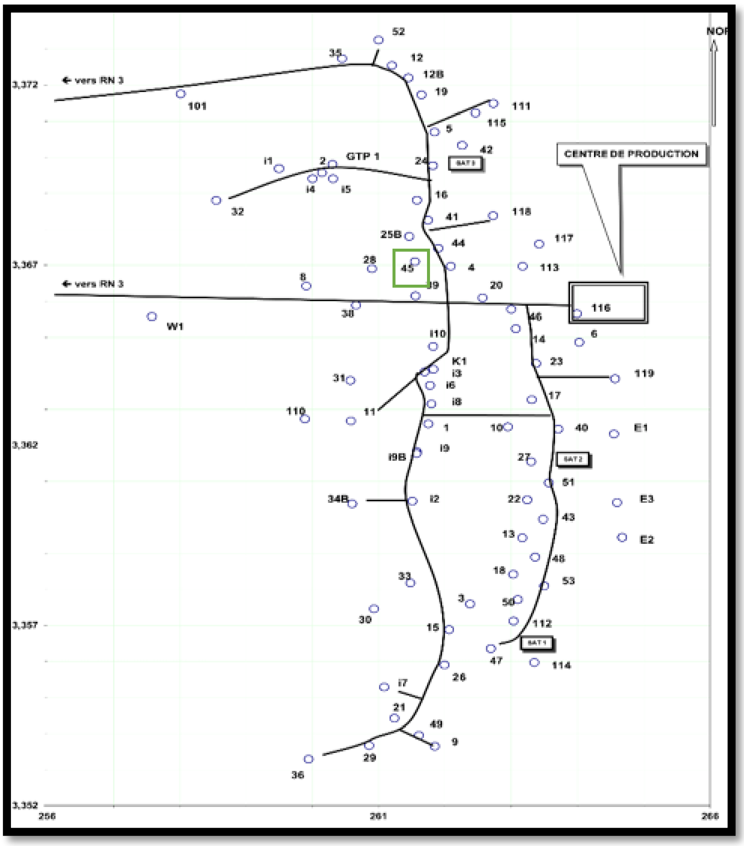


Figure 57: Locating well GT45 in the GASSI TOUIL field [2].

1.4.1 Presentation of the Well Logging Data Collection

To identify the breakthrough points of the PLT (Production Logging Tool) campaigns, surveys were carried out in the wells selected for this study (Fig. 58).

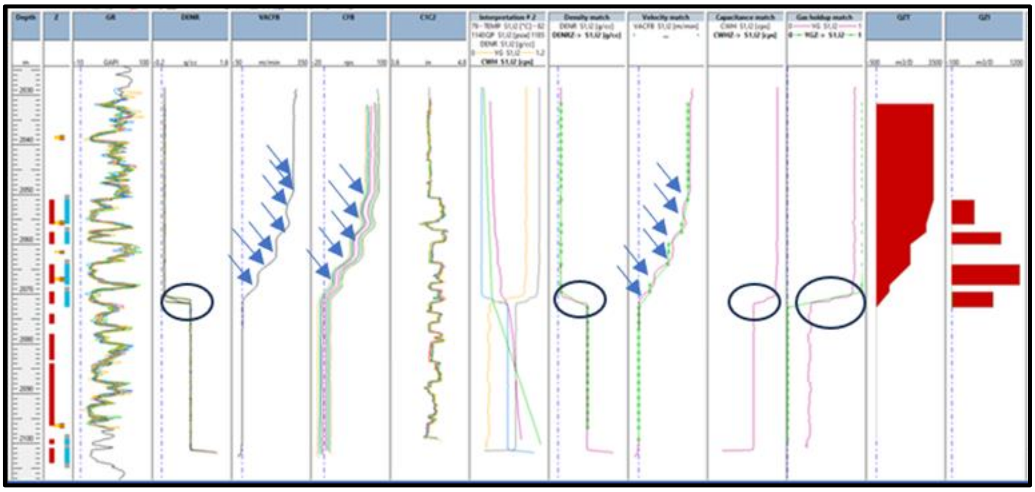


Figure 58: The production profile of the well-studied GT45 (according to the PLT conducted on 25/10/2021).

1.4.2 Results Discussion

A gas breakthrough is observed at well GT45 in the intervals (2051m - 2056m), (2057.5m - 2060m), (2064m - 2068m).

1.4.3 Solution Evaluation

Analyzing the PLT data revealed specific perforation intervals crucial for production

- Inflow Zone 4; (2051m- 2056m): 26724 Sm3/day of gas
- Inflow Zone 3; (1926m – 1930.5m): 59146 Sm3/day of gas
- Inflow Zone 2; (2064m-2068m): 81399 Sm3/day of gas.
- Inflow Zone 1; (2069.7m – 2072m): 49081 Sm3/day of gas, 10 Sm3/day of oil.

Table 4: Contributions per phase of well GT45 generated by the Emeraude software.

Inflow Zones	Top perf	Bottom Perf	Calculated Gas Rate (Sm3/j)	Calculated Oil Rate (Sm3/j)
Inflow Zone 4	2051	2056	26 724,00	-
Inflow Zone 3	2057,5	2060	59 146,00	-
Inflow Zone 2	2064	2068	81 399,00	-
Inflow Zone 1	2069,5	2072	49 081,00	10,00
No flow is Observed	2074	2076		
No flow is Observed	2078	2083,3	-	-
	2084	2096,5		
	2099,2	2100,2		
	2101	2104		
Total			216 350,00	10,00

From the interpretation, it's evident that there is no water present in any production zones, with the majority of gas originating from the inflow zone 2 (2064m-2068m), the inflow zone 3 (1926m – 1930.5m) and the inflow zone 4 (2051m- 2056m). The production profile suggests deactivating the inflow zones 2,3 and 4. So, the Reducing of gas breakthrough will be done with isolating the gas-producing perforations between two packers.

The figure below shows the results of the gauge tests that were carried out for the evaluation.

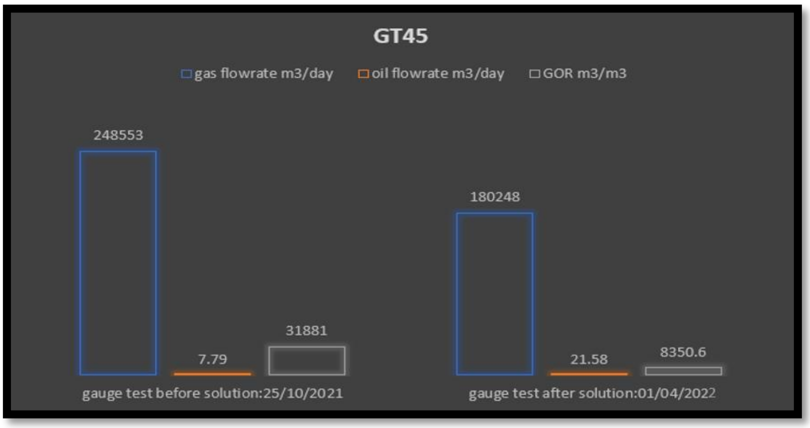


Figure 59: Comparison of the data from gauging test of well GT45

Before the packer setting, it is noted that the GOR value is very high, reaching approximately 31881 m^3/m^3. This explains the low oil flow rate compared to gas. After the packer setting, the oil flow rate increased to 21.58 m^3/day, while the gas flow rate decreased to 8350.6 m^3/day, and the GOR level decreased.

2. Sucker Rod Pump and Electrical Submersible Pump Technics

Activating wells enables the production of non-eruptive or underperforming wells, primarily focusing on oil wells. This activation may be required right from the start of exploitation when the reservoir lacks sufficient energy to lift the fluid from the bottom to the processing facilities.

2.1 Well, HC05

The Hassi Chergui field in GASSI TOUIL region represents 9% of the reserves in place and produces eruptively, it contains 10 production wells.

Among the wells in the Hassi Chergui field, we find well HC5 which has experienced a remarkable decrease in production flow over time, necessitating intervention to address this issue. Extraction from this well is done through natural eruption, but the decreasing energy is not enough to maintain the required level of oil production.

Well HC05 is an oil-producing well, it was drilled on 24/12/1981 in the HASSI CHERGUI oil zone. The well started production on 29/11/1982 with an oil flow rate of 139.49 m^3/day, and a Gas-Oil Ratio (GOR) of 862.8 m^3/m^3. On 21/12/2016, the oil flow rate (Qo) became 10.934 m^3/day, while the GOR was around 66 m^3/m^3. Therefore, it appears that the well has been production since its drilled, as shown in the historical oil production curves.

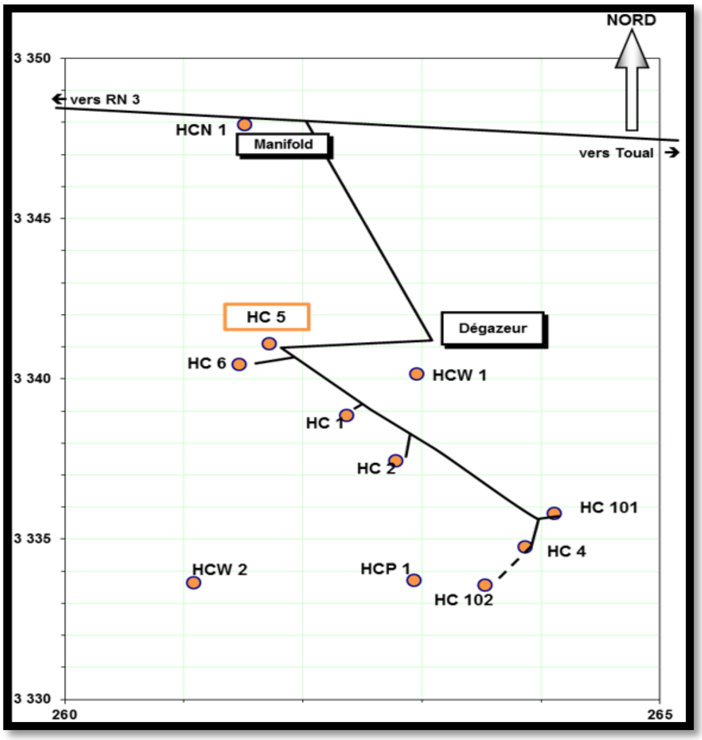


Figure 60: Locating well HC05 in the HASSI CHERGUI zone [2]

2.1.1 Data collection

- Oil well production performance diagram (Figure 49), (various production metrics for HC05, such as oil rate, water rate, and gas rate over time from 1982 to 2018).
- Gauging data: measurement of oil flow rates (Qo), gas flow rates (Qg), Gas oil ratio (GOR), HC05 (Before the implementation of the solution:21/12/2016.

presentation of the diagram data used: In order to identify decreases in flowrates (Qo, Qg and Qw), comprehensive surveys were conducted in the selected well.

- Note: These data are taken from the SONATRACH company's data bank.

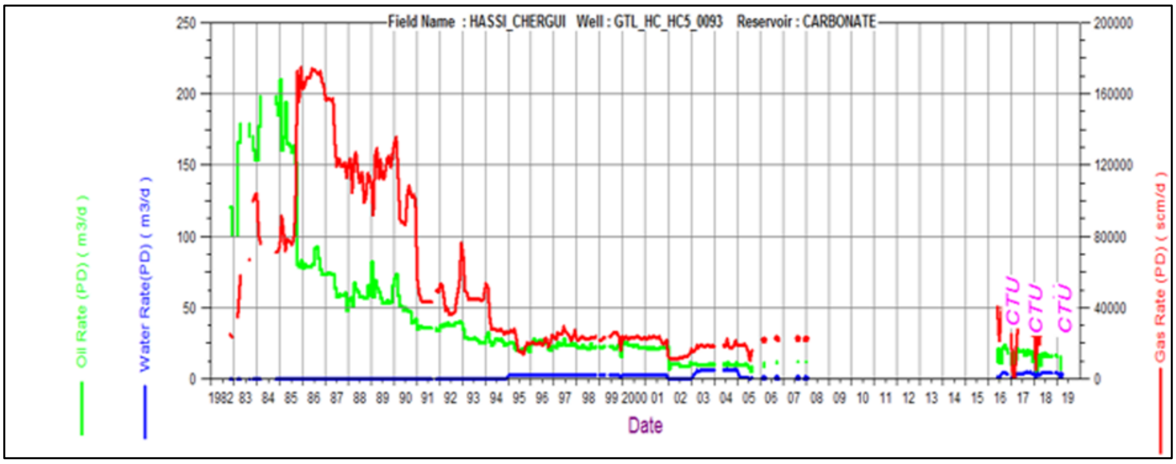


Figure 61: HC05 oil well production performance [2].

2.1.2 Results Discussion

In order to delve into the study and show the problems localized in the well HC05 by the oil well production performance diagram, the well will be commented on and evaluated.

- A decline in production flowrate is observed from 1989 to 2005
- A stop of production is observed from 2005 to 2016

2.1.3 Evaluation of Solution

The interpretation of the HC05 oil well production performance diagram (figure 55) data revealed:

- well production has experienced a continuous decrease from 1982 to 2005, due to depletion of the reservoir dropping from 139.49 m3/day to 12.5 m3/day.
- After 2005 the well production has stopped until 2016.

- On 26/08/2016, a good cleaning of the well was carried out, and the well was put back into service with an average oil production of 10.934 m3/day on choke 16/64. The wellhead pressure is low (240 Psig), and the well operated alone in the test battery (Ps Min).

Consequently, the extraction in this well occurs naturally through eruption, but when this energy fails to meet the production requirements, despite significant reserves in place, it has been suggested to equip this well with one of the different methods of artificial lift.

Table 5: comparison between the different artificial lift methods [7].

Artificial lift methods	Advantages	Inconvenient
Gas Lift	• Flexibility • Low investment required for well equipment • Adaptation for deviated wells • Possibility of sand presence • Reduced surface equipment for the well • Light interventions on the wells • Possibility of treatment • Potential use of on-site • Produced gas	• Need for a gas source • Restart issues during changing operating conditions • Importance of surface installations (GL compressors) • Process sensitivity to wellhead pressure • Deployment time • Limits of activation due to significant depletion • Corrosive formation gas • Hydrate issues • Adjustment of casing for gas lift • High-pressure installation

		• Low efficiency (10 to 30%)
Electric Submersible Pump	• High flow rates • Simple design • Space-saving • Good efficiency (35 to 60%) • No disturbances • Easy to operate • Possibility of installing sensors to measure bottomhole pressure • Can be installed in a deviated well, provided it is in a straight section • Low cost for high flow rates	• Not flexible (without a variable speed drive) • Presence of troublesome gas (15% maximum accepted with gas separator) • Intervention on the well with heavy equipment • Short lifespan if high well temperature (average of 1 year) • Stable electrical energy supply required • Not suitable for low flow rates (minimum of 30 m3/day for engine cooling) • Emulsion creation • Depth limited by cable voltage drop (maximum of 2400 m)
Progressive Cavity Pump	• Low investment cost • Small surface footprint • High efficiency (40 to 70%) • Easy installation • Suitable for a wide range of oil densities • Low maintenance costs	• Sensitive to the presence of h2s, co2, and aromatics • Tubing and rod wear • Limited operating temperature (max 122°c) • does not accept free gas

	• Suitable for deviated and horizontal wells • Accepts large quantities of sand	
Sucker Rod Pump	• Simple design • Surface adjustment flexibility • Pumping of viscous fluids • Low costs (purchase and maintenance) • Easy automation • Good efficiency (45 to 60%) • No temperature issues	• Friction in deviated wells • Low efficiency in the presence of gas • Limited depth • Bulky surface unit • Troublesome solids • Issues with paraffin • Low flow rates

Consequently, from this table we observe that

- Gas lift: this method may not be the best method for enhancing oil production in this particular scenario. due to its considerable distance from the gas source. Additionally, the requirement for a network to collect and inject gas would entail substantial economic costs.
- pumping: For well HC05, the selection of a Sucker Rod Pump (SRP) as the preferred artificial lift method over Progressive Cavity Pumps (PCP) and Electrical Submersible Pumps (ESP) is a professional decision.

based on

➢ Cost-Effectiveness: SRPs are generally more economical to operate and maintain compared to ESPs and PCPs, especially in wells with lower production rates. (The flow rate of HC05 is approximately 11 m3/day).

- <u>Simplicity and Reliability:</u> The design of SRPs is simpler, which often leads to higher reliability and easier maintenance. This can be particularly beneficial in remote or less accessible locations.
- <u>Ease of Maintenance:</u> SRPs are easier to troubleshoot and repair, which can reduce downtime and maintenance costs1.
- <u>Lower Energy Consumption:</u> SRPs can be more energy-efficient than ESPs, particularly in wells with lower flow rates1.
- <u>Adaptability:</u> SRPs can be adapted to changing well conditions with relative ease, allowing for continued operation even as the well characteristics change over time

After sucker rod pump setting

The table below shows the results of the gauging tests that were carried out for the evaluation.

Table 6: Comparison of the data from well gauge HC05

Well name	Gauging test	Qo m3/day	GOR m3/m3
HC 05	Before solution 21/12/2016	10.943	66
	After solution 04/10/2023	24.048	386

- Before the SRP setting, it is noted that the Qo value is 10,943 m3/day.
- After the SRP setting, the oil flow rate increased to 24.048 m^3/Day.

2.2 Well, GT35

The focus of this part is to rigorously evaluate the impact of Electric Submersible Pumps (ESPs) on the production efficiency of oil well GT35, situated within the GT field. The goal is to carefully determine the optimal ESP size that is in harmony with the well's unique characteristics to maximize the production rate. By leveraging the PIPESIM software, we will model the well GT35 and simulate various scenarios to pinpoint the most effective ESP configuration.

Well GT35 is an oil-producing well, it was drilled on 25/10/1966 in the GT oil zone. The well started production on 01/11/1966 with an oil flow rate of 184.1 m³/day, and a Gas-Oil Ratio (GOR) of 1144.5 m³/m³. On 14/05/2023, the oil flow rate (Qo) became 33,79 m³/day, while the GOR was around 676.96 m³/m³. Therefore, it appears that the well has been production since its drilled, as shown in the historical oil production curves.

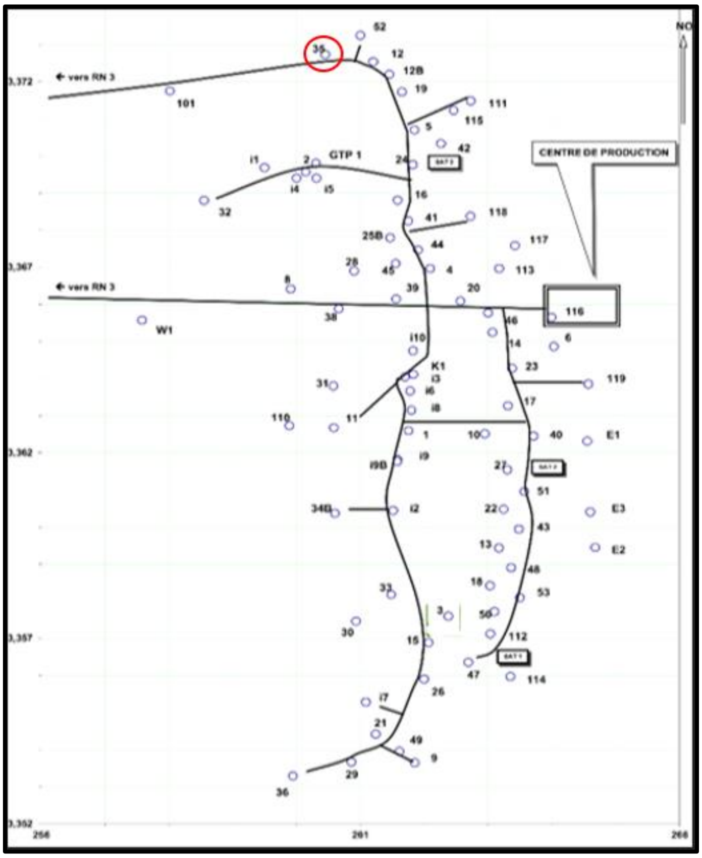


Figure 62: Locating well GT03 in the GASSI TOUIL field [2].

2.2.1 Data collection

- **Well Completion (Down Hole Equipment)**

The well model to be designed using PIPESIM software includes a section representing the production tubing, and the well are cased hole.

Table 7: Completion of well GT35 with an open hole

Well	Casing				Tubing			
	To MD(m)	ID (in)	OD (in)	Roughness (mm)	To MD(m)	ID (In)	OD (In)	Roughness (mm)
GT35	2092	6.366	6,653	0.0254	1975.15	3.958	4.23	0.0254

- **The heat transfer coefficients**

The aim is to determine the curve of Heat Transfer "Ambient Temperature = f(MD)" of the wells, these data have been presented in the following table:

Table 8: well GT35 heat transfer data

well	MD (m)	Ambient Temperature (Deg °C)	MD (m)	Ambient Temperature (Deg °C)
GT35	0	15.5	2092	82.5

- **The Latest Well Gauging Data**

The most recent gauging data is used to adjust the well model according to its latest oil flow rate, and this data is presented in the following table (from the DATA BANK):

Table 9: The Latest Well Gauging Data

well	Gauging Data	Qo (sm^3/d)	Qw (sm^3/d)
GT35	14/05/2023	33.79	63.62

- **Well Test Data**

In order to obtain a reliable well model (approximate to the real model), it was necessary to adjust the static and dynamic bottom pressures of this well. Therefore, well test data is required, which is obtained from DST and BUILD-UP tests. However, there were some corrections to be made before using this data. The difference between the elevation of the perforations and the elevation of the measurements obtained during the tests mentioned below lead us to consider the pressure losses between these two elevations, using the following equation:

$$\mathrm{BHP}s(perfos) = \mathrm{BHP}s(gauge) + \frac{\mathrm{dP}}{dh}(st) \times (Cote(Perfos) - Cote(gauge))$$

$$\mathrm{BHP}d(perfos) = \mathrm{BHP}d(gauge) + \frac{\mathrm{dP}}{dh}(st) \times (Cote(Perfos) - Cote(gauge))$$

Where

BHPs: Static bottom hole pressure.

BHPd: Dynamic bottom hole pressure.

$\frac{\mathrm{dP}}{dh}(st)$: Static pressure gradient [2].

In our case, the pressures PG and BHP are directly provided in corrected form. The table below summarizes the well test data:

Table 10: well test data

WELL	PG (Psig)	BHP (Psig)	Qo (Sm^3/d)	IP $Sm^3/(d.bar)$	Choke (mm)
GT35	1940	1940	33,79	2,4285	40

Finally, the data from the latest measurements are used to calibrate the well model by its most recent oil flow rate, and this data is presented in the following table:

- **PVT Data**

To have a reliable model representing the flow in our wells with the maximum accuracy, we must integrate the PVT data of these well effluents. The model used is the Black Oil model because it is the one that best corresponds to our case. Furthermore, the unavailability of the necessary sufficient data to apply the compositional or PVT model pushes us to opt for black oil, which remains applicable with the available data.

The necessary data to create this model are summarized in the following table:

Table 11: PVT Data

Well	Oil Density	GOR (Sm^3/Sm^3)	WOR (Sm^3/Sm^3)
GT35	0.801	676	1.883

2.2.2 Results Discussion

a) The reservoir model and well potential

Generally, the potential of a well is characterized by the flow rate delivered by this well if we consider that its bottom pressure can be reduced to atmospheric pressure, which is purely theoretical. We can calculate this maximum flow rate (AOFP) based on Darcy's law, which is used if the static bottom pressure (Pr) is higher than the bubble pressure (single-phase flow) and if we assume that the flow regime is steady [8].

$$\mathbf{Q = IP\ (Pr - Pfd)}$$

Where $\mathbf{AOFP = IP \times Pr}$

Knowing that IP and pressure Pr are available from well test data. The ultimate goal is to determine the performance curves "Q = f(P)" of wells capable of producing on the GASSI TOUIL field network to predict the flow rates produced by these well during the decline of their head pressure.

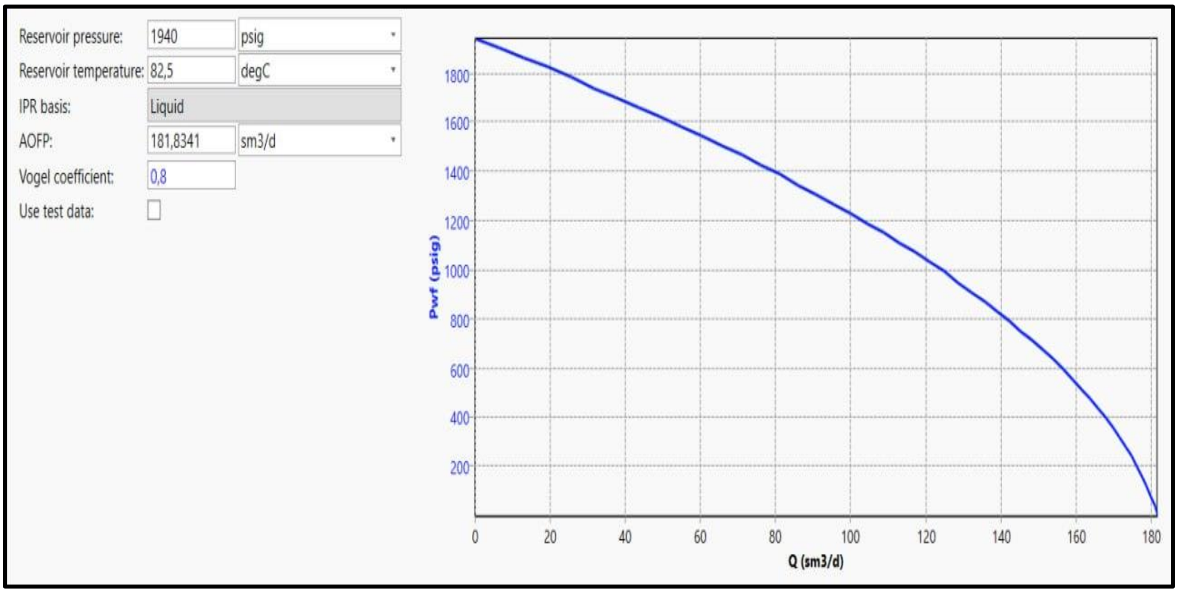


Figure 63: IPR Well GT35 model

From the fig. 63 we see that the AOFP value is around 182 sm3/d.

- ### Well GT 35 Modeling with PIPESIM

Once the well data (such as casing, completion details, and the results of the latest BUILD UP and GAUGING tests) are input, the software enables us to design our well.

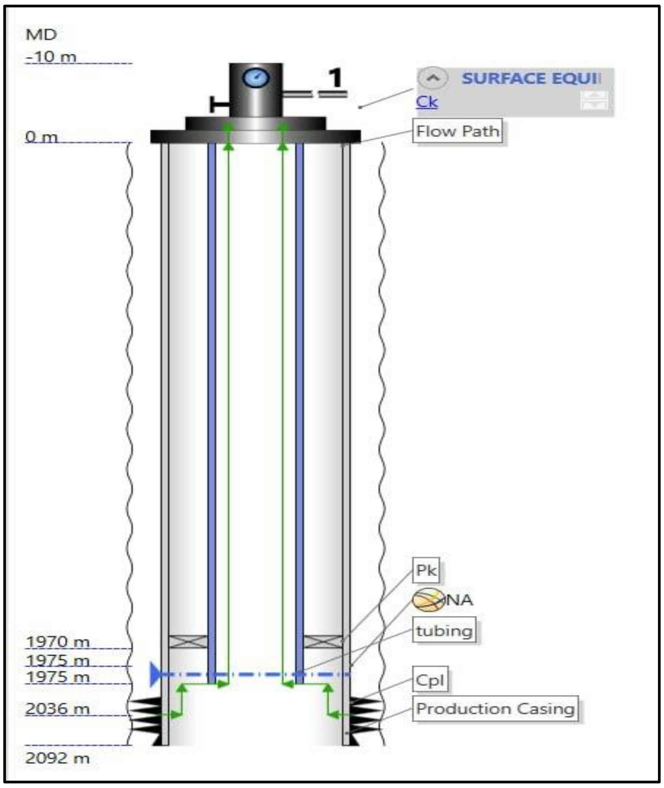


Figure 64: Well, GT35 design

We move on to the most important step.

- **Build-up Matching (well GT35)**

We will have to choose one of the of the vertical flow correlations:

• Ansari;

• Beggs & Brill Original;

• Beggs & Brill Revised;

• Duns & Ros;

• Govier, Aziz & Fogarasi;

• Gray (modified);

• Gray (original);

• Hagedorn & Brown;

• Hagedorn & Brown, Duns & Ros map;

• Mukherjee & Brill;

• ORKISZEWSKI.

The principle of choosing the appropriate correlation in the PIPESIM software consists of matching (comparing) the correlations with a test of measurements, that is, plotting the pressure gradient as a function of depth for each correlation mentioned above and comparing it to that of the test, the correlation to choose is the one that gives the closest gradient.

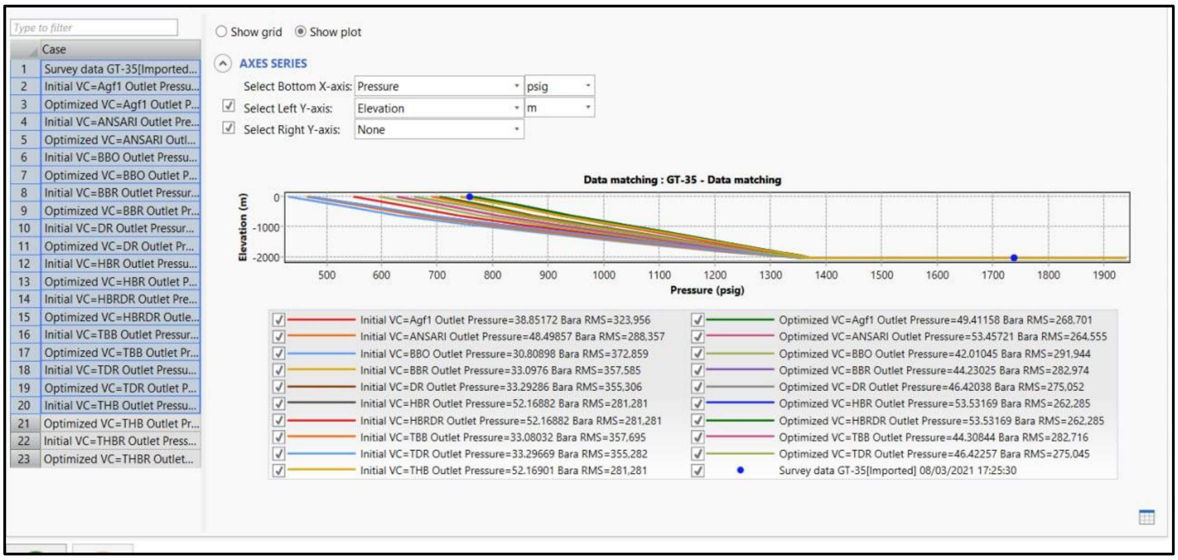


Figure 65:: The correlations used by the PIPESIM software to match the data

	Vertical multiphase correlation	Calibrated vertical friction factor	Calibrated vertical holdup factor	Calibrated U value multiplier	Initial pressure RMS	Calibrated pressure RMS	Initial temperature RMS	Calibrated temperature RMS	Initial holdup RMS	Calibrated holdup RMS	Initial total RMS	Calibrated total RMS
1	Hagedorn & Brown	0.959168	0.916176	2.468492	262.229059	261.896893	19.051562	0.387841	0	0	281.280621	262.284733
2	Hagedorn & Brown, Duns & Ros m...	0.959168	0.916176	2.468492	262.229059	261.896893	19.051562	0.387841	0	0	281.280621	262.284733
3	Hagedorn & Brown (Original) [Tuls...	0.959168	0.916176	2.468492	262.228969	261.898116	19.051564	0.387853	0	0	281.280534	262.285969
4	Hagedorn & Brown (Revised) [Tuls...	0.959168	0.916176	2.468492	262.228969	261.898116	19.051564	0.387853	0	0	281.280534	262.285969
5	Ansari	0.86303	0.728098	2.490714	269.320967	264.172684	19.035717	0.382797	0	0	288.356684	264.55548
6	Aziz Govier Fogarasi	1.03766	0.5	2.4823	304.989169	268.319964	18.9669	0.381212	0	0	323.956069	268.701176
7	Duns & Ros [Tulsa (Legacy 1989)]	1.059724	0.5	2.440308	336.383185	274.570463	18.898558	0.47486	0	0	355.281743	275.045323
8	Duns & Ros [Baker Jardine]	1.059724	0.5	2.440308	336.407496	274.576724	18.898513	0.474851	0	0	355.306009	275.051575
9	Beggs & Brill [Tulsa (Legacy 1989)]	1.122336	0.5	2.473572	338.776612	282.327692	18.917915	0.388386	0	0	357.694527	282.716078
10	Beggs & Brill Revised	1.111363	0.5	2.476624	338.666809	282.588503	18.91806	0.385423	0	0	357.584869	282.973926
11	Beggs & Brill Original	0.5	0.5	2.462371	353.9559	291.533631	18.903115	0.410629	0	0	372.859015	291.94426

Figure 66: Calibrated total RMS of each correlation

(As seen in Fig. 66), we notice that the most appropriate correlation for calculating pressure losses in the tubing of well GT35 is: Hagedorn & Brown, Phase.

The following figure represents the result obtained during our Matching:

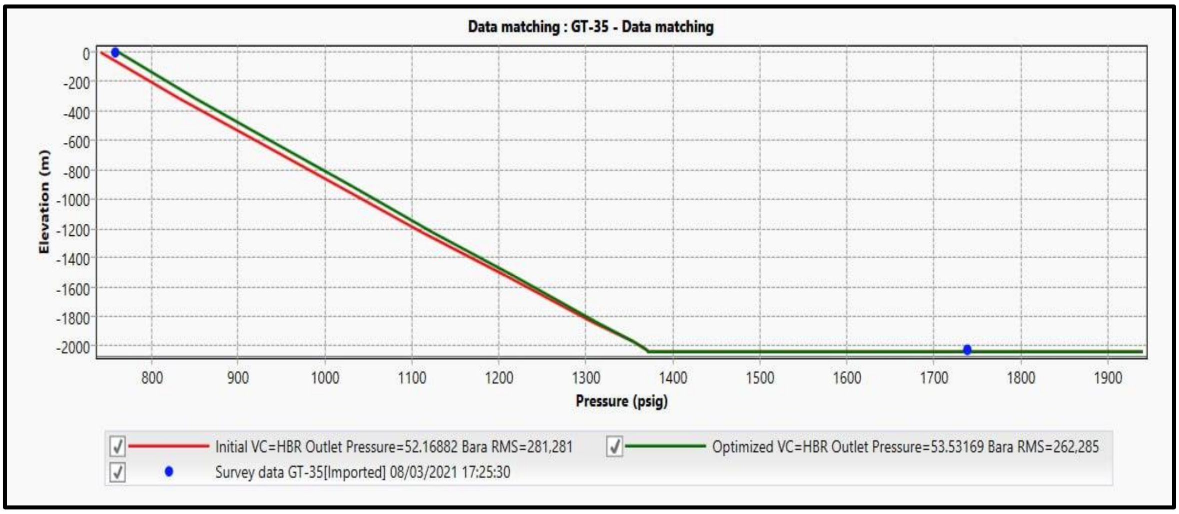


Figure 67: Build-up matched by the Hagedorn & Brown correlation of the GT35 well

We note that the obtained result is very satisfactory, so we only have the flow calibration left, which will be carried out using NODAL ANALYSIS mode, allowing us to fully calibrate our model.

We note that the obtained result is very satisfactory, so we only have the flow calibration left, which will be carried out using NODAL ANALYSIS mode, allowing us to fully calibrate our model.

- **Nodal Analysis Nodal analysis**

In order to obtain the operating point of the wells, which is a dynamic bottom hole pressure value and the corresponding flow rate, a simulation is carried out in nodal analysis mode to determine the potential of a well and then assess several parameters that affect the flow rate and the dynamic bottom hole pressure. But before these assessments are made, it is imperative to calibrate the current flow rates of the wells, and the following curves represent the obtained results fig. 68

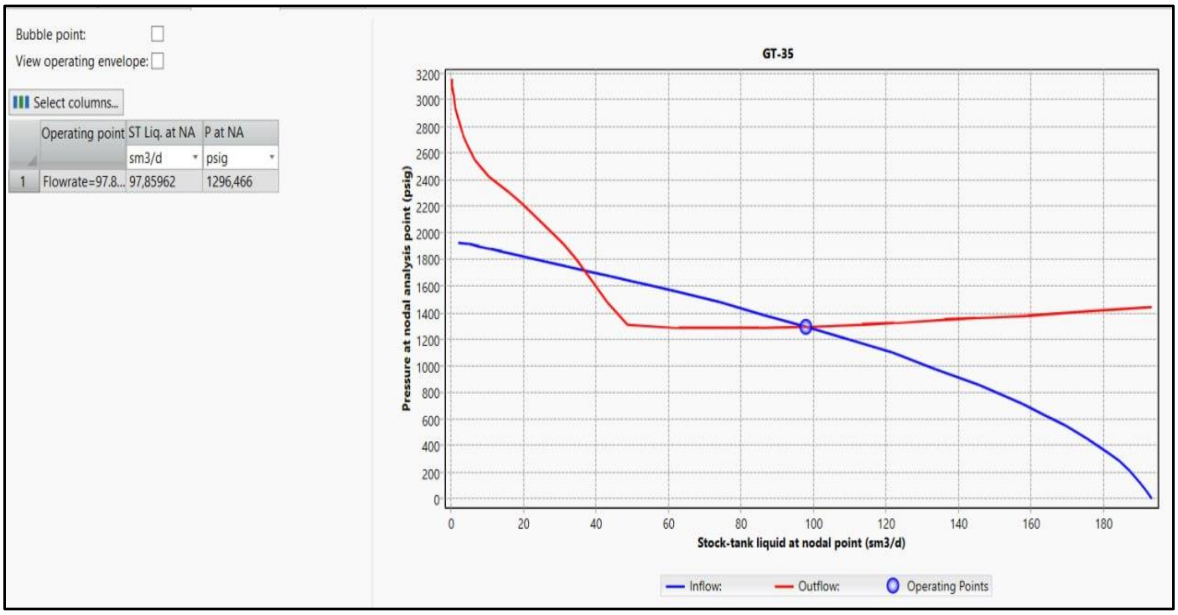


Figure 68: The NODAL ANALYSIS mode results of well GT35 before the update

2.2.3 Evaluation of Solution

a) ESP Optimization

We intend to switch the artificial lift method in well GT35 from gas lift to an Electric Submersible Pump (ESP). The switching due to the suboptimal production rates associated with the current system and the challenges posed by icing. This phenomenon causing the well to cease production for extended periods, sometimes up to 9 hours. Addressing the issue of icing is critical for maintaining continuous operation.

The icing, refers to the formation of ice-like solids called hydrates, which occur when free water and natural gas combine at high pressure and low temperatures. This can lead to operational challenges in oil and gas wells, including blockages and reduced flow rates, particularly under the cold conditions of winter

The ESP is a great choice for lifting oil with varying densities and viscosities, especially under high temperatures, and it's suitable for wells with a medium GOR value.

Casing ID:	6,366	in
Equipment clearance:	0,5	in
Design frequency:	60	Hz
Design flowrate:	170	sm3/d
Intake liquid rate:	7269,383	m3/d
Intake total rate:	7269,383	m3/d

Figure 69: operational data for ESP Design

➢ Optimization Procedure

Our aim is to find the most efficient ESP to maximize oil flow using the PIPESIM software. PIPESIM simplifies the process, saving time and reducing errors. Here are the steps to find the optimal flow:

• Entering operational data into PIPESIM, including changes in tubing diameter for the ESP.

• Using the ESP design window to input production rate values and various choices of ESPs, resulting in recommended pumps table.

• Choosing the best efficiency ESP design.

• Determining the optimal production flow rate.

Input the ESP design data into the program

We input the necessary data for optimization into PIPESIM.

	Manufacturer	Model	Series	Min. flowrate m3/d	Max. flowrate m3/d	Efficiency at d... %
1	Alkhorayef	WD-150	400	14,30886	44,51645	21,62
2	Alkhorayef	WG-2500	513	238,481	492,8607	16,82415
3	Alkhorayef	WD-450	400	39,74683	87,44303	9,089296
4	ALNAS	S1000	362	116,0607	197,9392	5,312538
20	ESP	TA900	338	104,9316	168,5265	0,076884
21	REDA	MT2A-30	272	23,99534	44,39148	0,07122156
22	ESP	TD280	400	15,89873	79,49365	0,06269889
23	ODI	W2	45	0	58,06534	0,05811277
24	ODI	RAT5	55	50,87594	76,31391	0,05698477
32	ALNAS	ANA530	92	24,00708	48,01417	0,04300517
33	ALNAS	ANM520	92	24,00708	48,01417	0,04300517
34	REDA	D475N	400	31,79746	99,36707	0,04222426
35	REDA	D475N(387)	387	31,79746	99,36707	0,04222426
36	ESP	TA400	338	47,69619	85,85314	0,04203699
37	ALNAS	ANA580ES	92	72,02125	138,001	0,04137667
38	ESP	TD1200	400	127,1898	238,481	0,04075377
39	XPC	D420EZ	400	49,28606	84,26327	0,04023819

Figure 70: The ESP's choices proposed by PIPSEM

From the table, we have determined that the ESP TD1200 is the most suitable electric submersible pump for our requirements. The decision is based on the optimal flow rate necessary at the intake of the ESP in this particular well, which falls within the minimum and maximum operational flow rate range of the ESP TD1200 model.

The optimal flow rate at ESP intake that show in figure below:

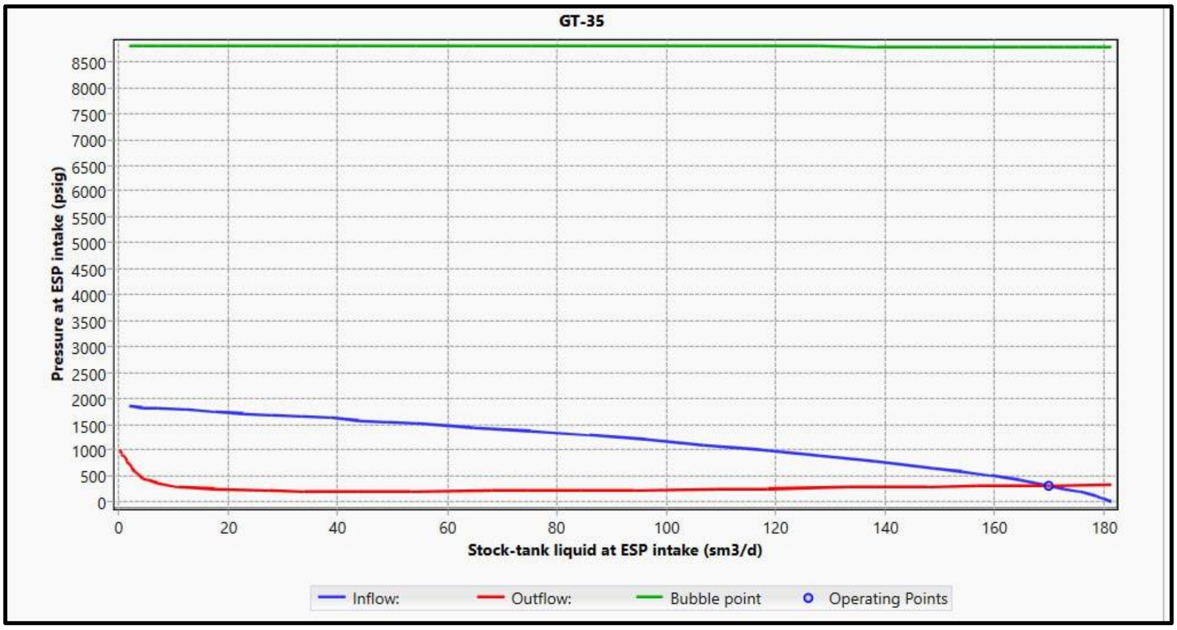


Figure 71: nodal analysis after the setting of the pump choice

- ➢ we will determine if the pump is operating safely and efficiently depending on data used:

we have 3 cases

- if the peaks of (efficiency curve and power curve) and the dotted line of optimal flowrate are all in the safe zone in the actual pump performance curve, so our pump choice is operating safely and efficiently.
- If the dotted line of the optimal flowrate is before the safe zone in the actual pump performance curve, so we have a problem that we call it downthrust.
- If the dotted line of the optimal flowrate is after the safe zone in the actual pump performance curve, so we have a problem that we call it upthrust.

- ➢ Upthrust and downthrust: Upthrust and downthrust are forces that act on an ESP during operation. They are caused by the interaction of the pump with the fluid being pumped and the wellbore.

Upthrust is a lifting force that acts on the pump in the upward direction. It is caused by the pressure of the fluid being pumped acting on the impeller and diffuser vanes of the pump. Upthrust can be beneficial because it helps to counteract the weight of the pump and reduce the load on the bearings. However, excessive upthrust can cause the pump to vibrate and become damaged [12].

Downthrust is a downward force that acts on the pump. It is caused by the weight of the pump and the downward pressure of the fluid being pumped. Downthrust can be detrimental because it can cause the pump to wear and tear more quickly. It can also lead to problems with the bearings and seals [12].

The amount of upthrust and downthrust that acts on an ESP depends on a number of factors, including:

- The size and design of the pump
- The flow rate of the fluid being pumped
- The properties of the fluid being pumped
- The depth of the well

It is important to carefully consider the upthrust and downthrust forces when selecting and operating an ESP. By doing so, you can help to ensure that the pump operates safely and efficiently.

the figure below shows if the pump that we choose is operating in good conditions.

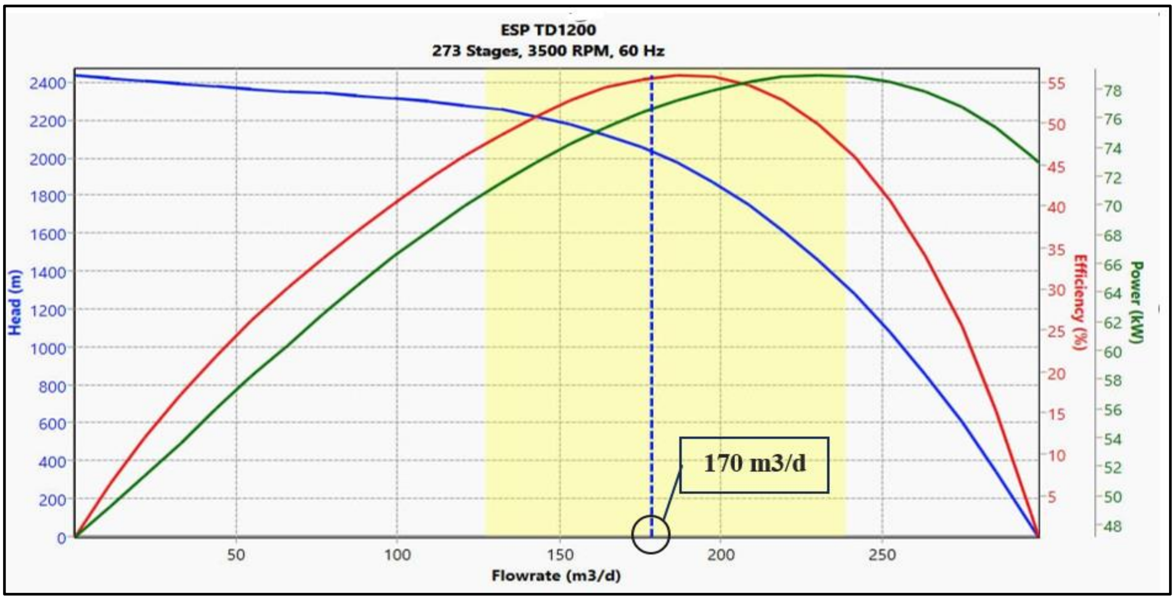


Figure 72: pump (ESP TD 1200) performance curve

from the actual pump performance curve figure (72), we noted that the peaks of (efficiency curve and power curve) and the dotted line of optimal flowrate are all in the safe zone.

so, our pump choice is operating safely and efficiently.

Table 12: Pump (ESP TD1200) parameters

pump	ESP TD1200
Stages	273
speed	3499.992 (rpm)
efficiency	55.35041%
power	76.36778 (kw)
Head	2054.357 (m)
Differential pressure	2990.468 (psi)
Discharge pressure	3314.306 (psig)

Chapter V: Conclusion and Recommendations

1. Conclusion

As we conclude, The GT03 well presents a unique challenge due to the co-location of gas breakthrough and oil production zones. This means that any attempt to shut off the gas would also inadvertently restrict the flow of oil, which is not desirable.

For wells like GT30 and GT45, where gas breakthrough zones are distinct from oil production zones, the use of packers is an effective solution.

Packers will serve as barriers, isolating the gas-rich zones. This isolation helps in maintaining the integrity of the oil production zones (GT30 from 54.42 m3/d to 161.5 m3/d and GT45 from7.79 m3/d to 21.58 m3/d) and mitigates the issues associated with high GOR.

The Sucker Rod Pump (SRP) has proven to be an excellent choice for well HC05. It's cost-effective, reliable, and optimizes the well production rate from 10.943 m3/d to 24.048 m3/d. This makes it a professional and practical solution for the well's long-term operation, ensuring steady oil production with manageable costs. Essentially, the SRP is a wise choice for efficiently maintaining the well's production rate.

Also, selection of the Electric Submersible Pump (ESP) has been instrumental in optimizing the liquid production flowrate in well GT35 from 97.85 m3/d to 170 m3/d The comprehensive analysis and simulations conducted have allowed us to choose an ESP (TD1200) that functions efficiently (55.35%) within the desired flow rate range (170 sm3/d).

2. Recommendation For Future Work

The following are some recommendations for future work:

- To maintain the productivity and longevity of the GASSI TOUIL wells continuous PLT campaigns are crucial. These campaigns yield essential data on the wellbore's flow profile, vital for evaluating packer performance and detecting new gas breakthroughs or water coning. The data should inform adjustments to packer settings and the development of further remedial actions.

- For GT03, where gas and oil zones overlap, traditional gas shutoff is impractical. Instead, innovative strategies like variable choke control and water/gas injection are advisable. Mechanical solutions, like the installation of downhole separation devices or inflow control devices, can also be effective. These methods aim to optimize production without impeding oil flow.
- chemical treatments such as polymer flooding or gel treatments can improve zonal isolation Mechanical solutions, like the installation of downhole separation devices or inflow control devices, can also be effective. These methods aim to optimize production without impeding oil flow.

Artificial lift methods can be utilized to produce wells that are dead or to maximize the production rate from flowing wells.

To maximize the efficiency and cost-effectiveness of The SRP system, it is crucial to consider the following recommendations:

- Conduct daily checks to prevent any brief lapses in attention from causing irreversible issues, such as fluid leaks due to poor sealing between the polished rod and stuffing box.
- Adhere to the manufacturer's guidelines for maintenance and parts replacement to ensure optimal system functionality.
- After 20 days of production, it is advisable to perform echometric and dynamometry procedures to assess system performance and efficiency. Here's what these operations involve:

1. Echometric: This procedure helps determine the liquid level in the annulus, ensuring proper pump submergence, checking functionality, indirectly measuring bottom hole and reservoir pressures, and monitoring productivity index changes.

2. Dynamometry: By measuring forces and torques applied by the system, dynamometry detects faults, overloads, excessive vibrations, or other mechanical issues that could impact performance.

- Consider installing a Variable Speed Drive (VSD) system and Rod Pump Optimization Controller (RPOC) for further system optimization.

To maximize the efficiency and cost-effectiveness of The ESP system, it is crucial to consider the following recommendations:

- The inverted ESP (pump at the bottom, motor at the top) / integrated CT installation can be used in remote areas and offshore where the cost of workover rig is high and the loss of production is a major concern.
- The Variable Speed Drive (VSD) is recommended to adjust the ESP operating speed to fit the characteristics of the well which are changing over time.
- This adjustment can be best utilized to maximize production by changing frequencies. VSDs are usually applied to change frequencies from a range of 30 to 90 Hz.
- If produced water is managed and reservoir pressure is maintained, installing ESPs at the beginning of the field life is recommended to maximize oil and gas production. As results, oil and gas recovery will be maximized.

Reference

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- **[2] SONATRACH** Document, 2024. "EP DIVISION"
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- **[5]** Gas Shut-off Treatment in Oil Carbonate Reservoirs in Saudi Arabia | SPE Annual Technical Conference and Exhibition | ONEPETRO
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- **[7] D. BOUDRAA, L. MIRA.** Activating Wells Using Sucker Rod Pumps (Sucker Rod Pump)/Internship Report.
- **[8] ABBOU, Y. MAHAMDIOUA** Optimizing the Production Chain in The Northern Region of The REB Field Thesis. BOUMERDES University,2013.
- **[9]** Submersible Pump Handbook Eighth Edition BAKER HUGHES CENTRILIFT
- **[10]** Electrical Submersible Pumping (ESP) Systems by **MATTHEW AMAO**, king SAUD university,2014
- **[11]** Sucker rod pumps - Artificial Lift - Completions | SLB
- **[12]** PEH: Electrical Submersible Pumps - PETROWIKI (spe.org)

Annex

GT-35	FICHE TECHNIQUE	COORDONEES UTM	X= 260450,00
			Y=3372720,00
	RESERVOIR TAGS	COUPE TECHNIQUE	Zsol = 204,00 m
			Ztab = 209,00 m

EQUIPEMENT DE SURFACE

DESIGNATION	TYPE & DIMMENSION
CASING HEAD OCT 22	13"5/8 3K
CASING SPOOL OCT 29	13"5/8 3K x 11" 5K
TUBING HEAD OCT	11" 5K x 7" 1/16 5K
ADAPTEUR	7"1/16 5K x 2"1/8 5K
SUSPENSION OCT	OLIVE 3 1/2 EU CTU 30 E
ARBRE de NOEL	3" 1/8 -3000 FMC à l'exception LVM Cam

EQUIPEMENTS DE FOND

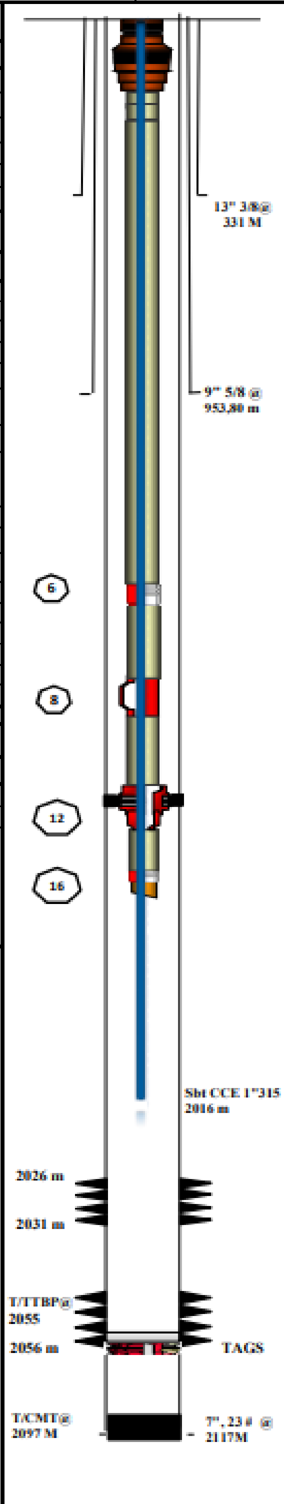
N	DESIGNATION	BOTOM	LONG	TOP
1	Olive de supention l=0,27 m (0,18 m)	0,18	0,18	0,00
2	Reduction 3"1/2 Vam X 3" 1/2 EU L = 0,79 m	0,98	0,80	0,18
3	Tubing 3" 1/2 N . Vam N 80 9,20 #	9,98	9,00	0,98
4	Pup joint 3"1/2 Vam	10,97	0,99	9,98
5	200 Tubing 3" 1/2 N . Vam N 80 9,20 #	1900,39	1889,42	10,97
6	**Siege " X " OD =3" 7/8 L =0,32 m ref : X Line x 84 792226 2,750 X LN 3"1/2 OD 9,20 # Vam**	**1900,71**	**0,32**	**1900,39**
7	Tubing 3" 1/2 N . Vam N 80 9,20 #	1909,79	9,08	1900,71
8	**Mondrin 3"1/2 Vam L =2,04 m OD =5"1/4 , ref : 0,5525 -BEL - 21033 job NO 0885328 8/95 int 7000 psi , ext 5500 psi 2,5K KBUG 13380 9,20 # Vam**	**1911,83**	**2,04**	**1909,79**
9	6 Tubing 3" 1/2 N . Vam N 80 9,20 #	1968,52	56,69	1911,83
10	Red 4"1/2 X 3"1/2 Vam	1969,06	0,54	1968,52
11	**Anchor seal : OD =5"1/2 L =0,52 m , ref:44388110 422 B 82 FA 47**	**1969,27**	**0,21**	**1969,06**
12	**Packer 7" L=1,19 m (0,72m) OD 6"**	**1970,46**	**1,19**	**1969,27**
13	Reduction 4" LTC X 3"1/2 Vam L =0,17m OD=4"1/2	1970,63	0,17	1970,46
14	Pup joint 3"1/2 Vam 9,20 # N80 L=1,98	1972,61	1,98	1970,63
15	Pup joint 3"1/2 Vam 9,20 # N80 L=1,99	1974,60	1,99	1972,61
16	**Siege " XN" : 11XN 27560-A 0479434 XN 2,750 landing Niple Blank NO**	**1974,97**	**0,37**	**1974,60**
17	sabot 3"1/2 Vam L =0,16 OD 3"7/8	1975,13	0,16	1974,97

PERFORATIONS

DATE	DIAM	DENSITE	TYPE	TOP	BTM	REMARQUE
OCT -66	2,125	13	SMM	2026	2027	13 PERFOS
	2,125	13	SMM	2028,5	2031	
	2,125	13	SMM	2036,5	2038,5	
	2,125	13	SMM	2040,2	2041,5	
	2,125	13	SMM	2042,2	2048,5	
	2,125	13	SMM	2051	2054	
	2,125	13	UNIJET	2054	2056	

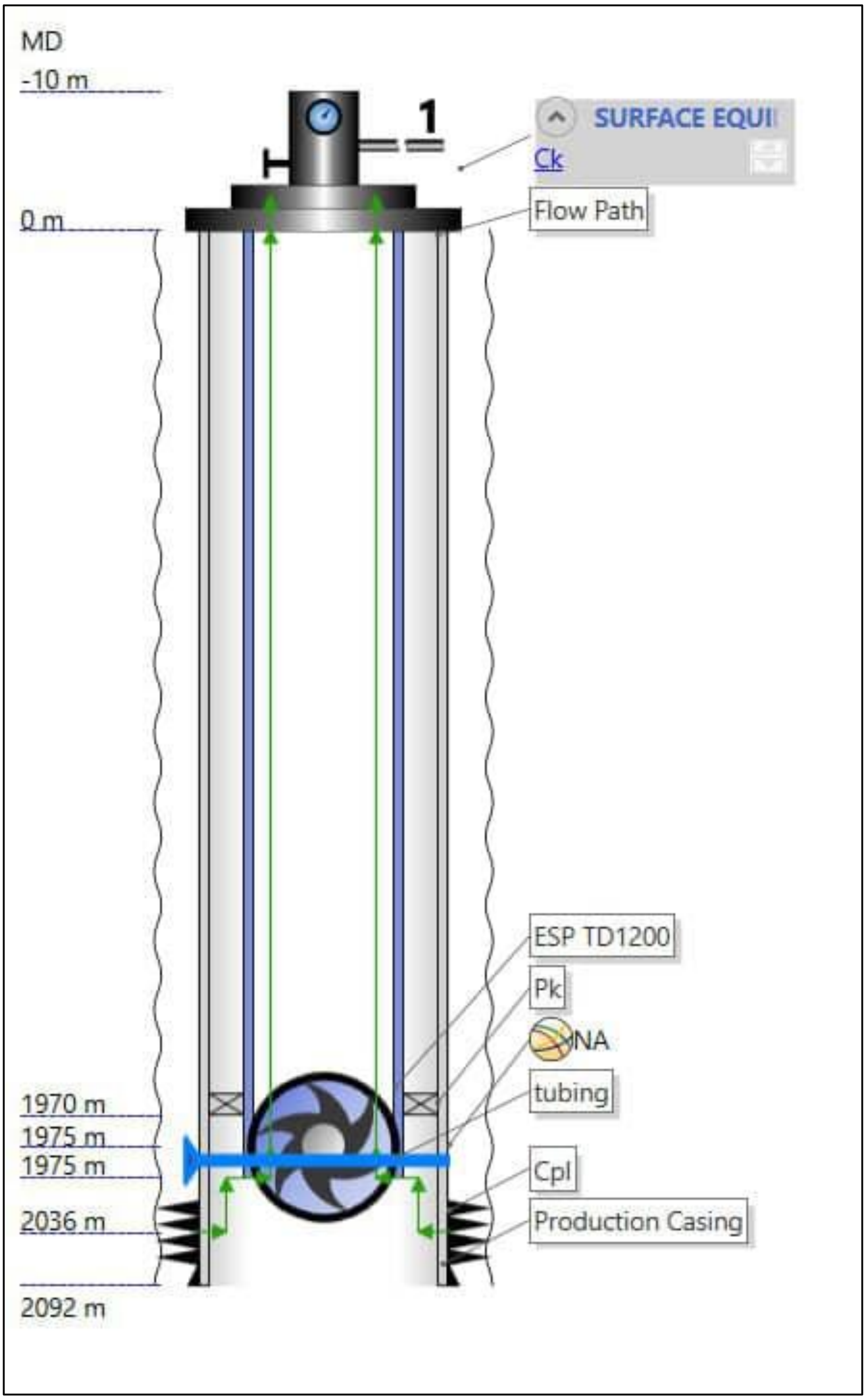
OBSERVATIONS

1-**Forage :** du 21/09/1966 au 25/10/1966
2-**Mise en production : 01/11/1966**
3- WORKOVER:
-**1er WO** : Debut : 30/04/1970 ; Fin : 07/05/1970 pour thangement tubing et rééquipement puits en injection sous packer
-**2eme WO** : Debut : 10/04/2009 ; Fin : 14/05/2009 _ Cabot 1200 , TP 186 ,Investigation du tubage 7'' et 9''5/8 et changement du tubing percé.
3- SNUBBING
-**1er SNB :** Début : 03/04/2010 ; Fin 18/04/2010 _appareil SNB HRL 8 pour **Installation CCE.**
-**2eme SNB :** Début : 19/06/2015 ; Fin 12/07/2015 _ **pour changement CCE.**
-**3eme SNB** :Début : 24/02/2020 ;Fin SNB 14/03/2020 _appareil SNB HRL 8 **echec retrait de CCE** coupé CCE (Top CCE@ 316,87 m)
-**4eme SNB** :Début : 07/01/2021 ;Fin SNB 26/01/2021 _Appareil: HRL 09 ENSP **retrait de CCE** .
4- Opération de PLT : Le 08/03/2021 avec HESP pour detection des zones productrices d'eau.
5- Opération de pose de TTBP : TTBP encrer a 2055 m au lieu 2035 m (échec de l'opération d'isolation) .
6-Opération WL avec SLB : Confirmation Top TTBP @ 2055 m/TR
- **4eme SNB** : Début : 29/08/2021 ; Fin 31/08/2021 _appareil SNB HRL 8 pour Installation CCE.

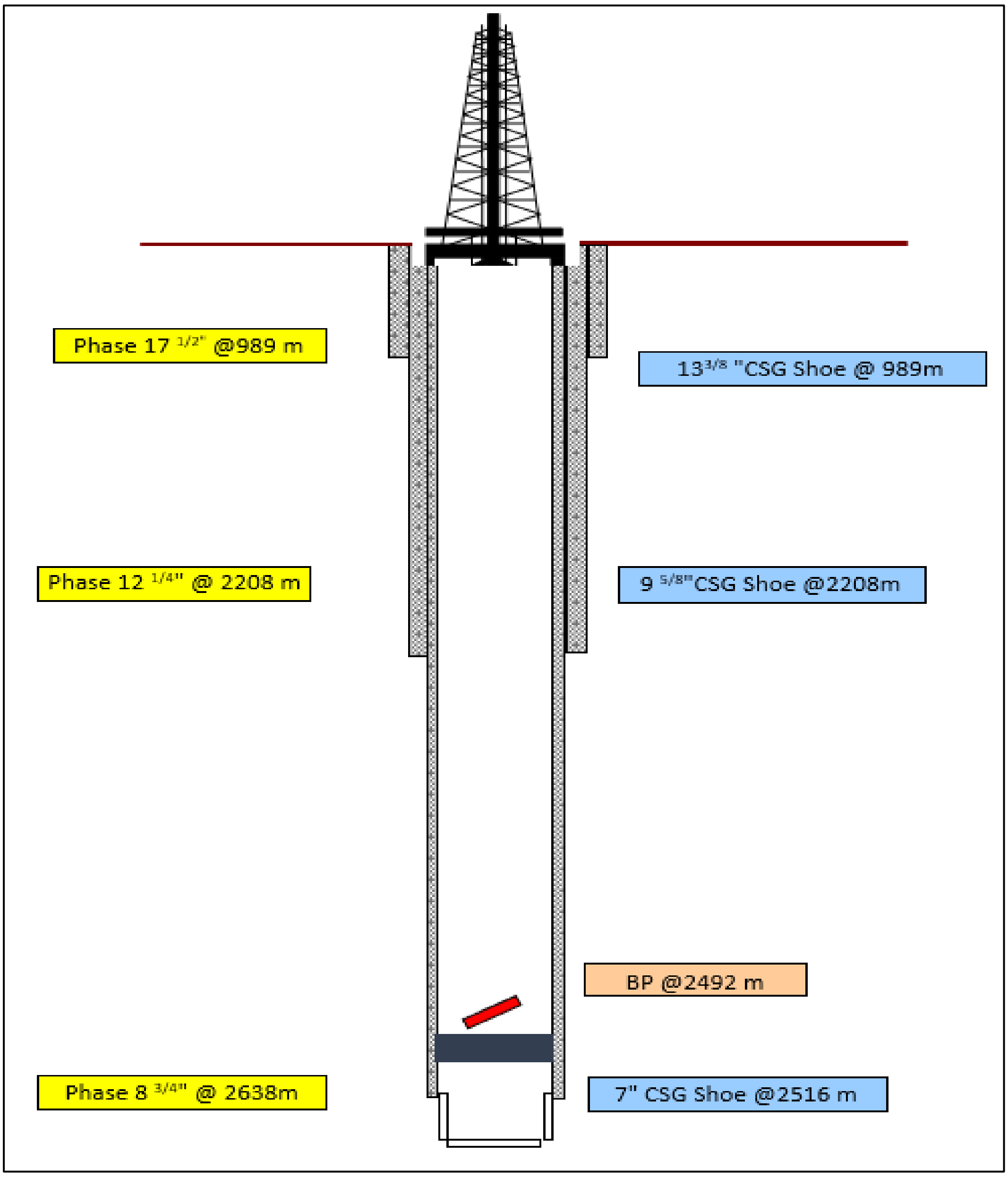


Mise à jour le 11/09/2021 par Sce T.Puits

Annex 1: technical data sheet of well GT35



Annex 2: well, GT35 design with PIPSEM software



Annex 3: Well, HC05 Design

HC-5	FICHE TECHNIQUE	COORDONEES UTM	X= 261716,514
			Y= 3341112,198
	RESERVOIR TRIAS ARGILO CARBONATE	COUPE TECHNIQUE	Zsol = 222,63 m
			Ztab= 227,81 m

EQUIPEMENT DE SURFACE

DESIGNATION	TYPE & DIMMENSION
CASING HEAD	13"5/8 3K
CSG SPOOL	13"5/8 3K x 11" 5K - FMC -
TG HEAD	11" x 7"1/16 5k - Cameron -
ADAPTEUR	7 1/16" x 3"1/8 5 k - Cameron -
BRIDE TARAUDE	3"1/8 5K X 3"1/8 LP
B.O.P	3"1/8 5K double (blind & piperam 1"1/4)
FLOWTEE	3"1/8 LP

EQUIPEMENTS DE FOND DU COMPLETION

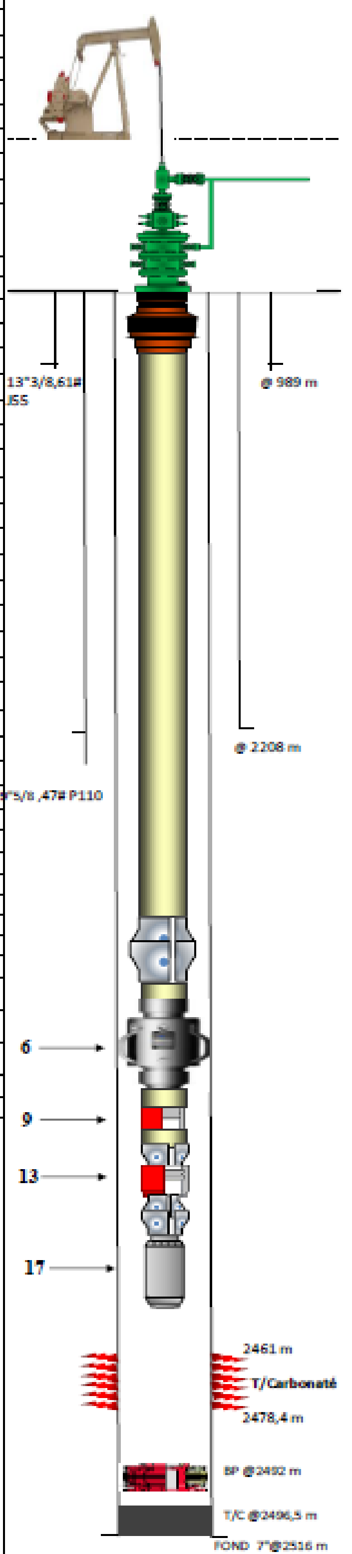
N	DESIGNATION	LONG	TOP
1	**Tbg hanger 7" NEW VAM BTM /UP (H-BPV 3''1/32)**	**0,300**	**0,00**
2	251 JOINT TBG 3.5" 9.2# HSC P110	2370,352	0,30
3	X-Over X 3"1/2 EUE Pin x 3"1/2 HSC Box	1,431	2370,65
4	X-Over X 2"7/8 EUE Pin x 3"1/2 EU Box	0,240	2372,08
5	Tubing 2"7/8 EUE 6,50#	9,472	2372,32
6	**Hydr-Tubing anchor catcher 7" (OD = 5"5/8 ID = 2,478 IN)**	**1,040**	**2381,80**
7	2 Tubing 2"7/8 EUE 6,50#	18,919	2382,84
8	Monchon 2"7/8 EU	0,137	2401,75
9	**Pump setting Nipple 2"7/8 EUE (OD = 3"1/8 ID = 2"1/8)**	**0,190**	**2401,89**
10	Tubing 2"7/8 EUE 6,50#	9,476	2402,08
11	Pup joint 2"7/8 EUE 6,50#	1,943	2411,56
12	X-Over 2"3/8 EUE Box X 2"7/8 EUE Box	0,300	2413,50
13	**BXN Nipple 2"3/8 EUE (1"875 X 1"791) Pin/Pin**	**0,268**	**2413,80**
14	X-Over 2"7/8 EUE Pin x 2"3/8 EUE Box	0,250	2414,07
15	Monchon 2"7/8 EU	0,137	2414,32
16	X-Over 3"1/2 EUE Pin x 2"7/8 EUE Pin	0,165	2414,46
17	**Gas separator 3"1/2 EUE (OD = 5"1/4 ID = 1"1/2) plugged**	**2,300**	**2414,62**
18	FIN COMPLETION		2416,92

EQUIPEMENTS DU POMPE DE FOND

N	DESIGNATION	LONG	TOP
1	Pompe, ouverture (la course) 6,03m, RHAC 22.3.2.0	8,270	0,00
2	Stabilisateur OD 2"1/4	1,100	8,27
3	(10) Sinker Bar L= 7,62m	76,200	9,37
4	(120) Rods D 3/4", L= 7,62m	914,400	85,57
5	(100) Rods D 7/8", L= 7,62m	762,000	999,97
6	(84) Rods D 1", L= 7,62m	640,080	1761,97
7	(2) Pony Rod, L= 1,85m	3,700	2402,05
8	Polished Rod, L= 7,85m	7,850	2405,75
7	FIN		2402,05

PERFORATIONS

DATE	DIAM	DENS	TYPE	TOP	BTM	REMARQUE
07/12/1981				2461,00	2463,00	
				2468,00	2470,00	
				2476,00	2478,00	



Mise a jour le 24/05/2023 par Sce Tpuits

OBSERVATIONS :

Debut Forage : 24/06/1981 , Fin de Sondage : 24/12/1981 Rig Name CABOT 1200_SH187

1er W.O : Début wo 22/05/2007 ; Fin wo 12/08/2007
But de la reprise: éliminant la communication franche entre le tubing et le casing.

2ème W.O : Début wo 19/01/2023 ; Fin wo 27/02/2023
But de la reprise: - Élimination de la communication
- Changement de la complétion pour l'installation du sucker Rod Pump

Installation de SRP: 16/05/2023 ; 02/06/2023

Annex 4: Technical Data Sheet of Well, HC05