PEOPLE'S DEMOCRATIC REPUBLIC OF ALGERIA
Ministry of Higher Education and Scientific Research

Serial Number: 2024 /2025

University of Kasdi Merbah Ouargla

Faculty of Hydrocarbons, Renewable Energies and Earth and Universe Science

Hydrocarbon Production Department

Thesis

To obtain the Master's degree

Option: Professional Production

Presented By:

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-THEME-

Gas lift systems: Design and optimization of Well ONM112

Defended on: 15 / 06 /2025 before the examination committee

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University Year 2024/2025

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ACKNOWLEDGMENT

First and foremost, we wish to express our gratitude to Allah, the Compassionate and Merciful, for granting us the strength and .patience to successfully complete this modest work

We would like to convey our sincere thanks to our supervisor **Mr. Boutalbi Mohammed chaker**, for his availability, seriousness, and valuable advice

We extend our warm thanks to our promoters at SONATRACH **Mr. Mohamed Amine Djeldjel** and **Mr.Sebaa Mohamed El-Fateh**, for their assistance, encouragement, and invaluable guidance .throughout the project period

Finally, we thank all those who have contributed, either closely or remotely, directly or indirectly, to the success of this work to which we have dedicated so much. We also wish to thank all the instructors of the Hydrocarbon Production Department at the University of Ouargla, who have contributed to our education.

Dedication

No pleasure can equal that of sharing one's happiness with loved Ones.

As I reach the end of my studies, I am greatly honored to dedicate this modest work:

To my dear mother, to whom I owe everything I am, who has always been there for me and has never ceased to pray for my happiness.

To my dear father, for all the advice he has given me, the support he has shown me, and the sacrifices he has made to see me succeed.

,To my dear brothers and sisters, To my entire extended family

To all my friends.

BEN HACHEM TAHIR / ABDOUALI MOHAMMED AMINE

Dedication

I would like to express my sincere gratitude and deep respect to all our esteemed professors at the Faculty of Hydrocarbons, Renewable Energies, Earth and Universe Sciences, especially those from the Department of Hydrocarbon Production.

I also extend my heartfelt thanks to all my colleagues, particularly our thesis supervisor, **Dr**. **Boutalbi Mohammed Chaker**, for his valuable guidance and continuous support throughout this work.

My gratitude goes as well to everyone who contributed to the completion of this humble work, whether directly or indirectly.

I wholeheartedly dedicate this modest work to my parents, my entire family, and all my fellow classmates.

MELLATI BRAHIM

Abstract

In mature oil fields like Hassi Messaoud, declining reservoir pressures necessitate artificial lift methods to maintain economic production, with gas lift being predominant. Gas lift reduces bottom hole flowing pressure by decreasing fluid hydrostatic pressure and mitigating rapid reservoir pressure drops. However, the limitations of available gas and compressor capacity necessitate optimization for maximum recovery. This study focuses on optimizing gas lift for well ONM112, which suffers from a production decline due to formation pressure dropping to 200 bar and a low gas-to-liquid ratio (GLR).

The research methodology involves comprehensive data collection, including well completion details, well testing data, and PVT analysis. Nodal analysis principles are then applied to optimize operational procedures by adjusting outflow expressions. This theoretical framework helps select optimal performance parameters to maximize production efficiency. Using PIPESIM software,. The results show a significant improvement,
achieving an optimum gas injection rate of 20000 Sm3/d and an increase in oil production rate by 5.87 m3/h for ONM112 well.

Additionally, this study proposes changes in tubing diameter, choke settings, and gas lift injection rate.

Keywords: Nodal Analysis, Correlation, Optimization, Outflow, Inflow, PIPESIM, Software, Artificial Lift Methods, Gas Lift, Hassi Messaoud Field, Well Completion, Inflow Performance Relationship.

Résumé

Dans les champs pétroliers matures comme celui de Hassi Messaoud, la baisse de la pression des réservoirs nécessite des méthodes d'élévation artificielle pour maintenir une production économique, l'élévation par le gaz étant prédominante. Le gas lift réduit la pression d'écoulement au fond du trou en diminuant la pression hydrostatique du fluide et en atténuant les chutes de pression rapides du réservoir. Cependant, les limites de la capacité du gaz et des compresseurs disponibles nécessitent une optimisation pour une récupération maximale. Cette étude se concentre sur l'optimisation du gas lift pour le puits ONM112, qui souffre d'une baisse de production due à la chute de la pression de formation à 200 bars et à un faible rapport gaz/liquide (GLR)

La méthodologie de recherche comprend la collecte de données complètes, y compris les détails de l'achèvement du puits, les données d'essai du puits et l'analyse PVT. Les principes de l'analyse nodale sont ensuite appliqués pour optimiser les procédures opérationnelles en ajustant les expressions de débit sortant. Ce cadre théorique permet de sélectionner les paramètres de performance optimaux pour maximiser l'efficacité de la production. En utilisant les logiciels PIPESIM ,. Les résultats montrent une amélioration significative, atteignant un taux d'injection de gaz optimal de 20000 Sm3/d et une augmentation du taux de production de pétrole de 5.87m3/h pour le puits ONM112.

En outre, cette étude propose de modifier le diamètre des tubes, les réglages du choke et le taux d'injection du gas lift.

Mots-clés : Analyse nodale, corrélation, optimisation, débit sortant, débit entrant, PIPESIM, logiciel , méthodes de levage artificiel, levage de gaz, champ de Hassi Messaoud, collection de données, complétion de puits, relation de performance de débit entrant.

ملخص

في الحقول النفطية الناضجة مثل حاسي مسعود، يؤدي انخفاض ضغط المكمن إلى ضرورة استخدام طرق الرفع الصناعي للحفاظ على إنتاج اقتصادي. يُعتبر الرفع بالغاز الطريقة السائدة، حيث يعمل على تقليل الضغط القاع الجوفي عن طريق خفض الضغط الهيدروليكي لعمود السوائل، مما يخفف من تأثير الانخفاض السريع في ضغط المكمن. ومع ذلك، فإن القيود المفروضة على كمية الغاز المتاحة وقدرة الضواغط تتطلب استراتيجية تحسين منهجية لتعظيم استخلاص الهيدروكربونات.

تركز هذه الدراسة على تحسين عمليات الرفع بالغاز للبئرONM122 ، الذي يعاني من انخفاض في الإنتاج نتيجة لانخفاض ضغط المكمن إلى 022بار، إضافة إلى انخفاض نسبة الغاز إلى السائل .(GLR) تتضمن المنهجية جمع بيانات شاملة، تشمل تفاصيل إكمال البئر، نتائج اختبارات الآبار، وتحليل الضغط والحجم ودرجة الحرارة .(PVT) بعد ذلك، يتم تطبيق مبادئ تحليل العقد (Nodal Analysis) لتحسين المعايير التشغيلية من خلال تعديل منحنيات الأداء الخارج وتحديد نقطة التشغيل المثلى.

باستخدام برنامج PIPESIM من شركة شلمبرجير، حدد التحليل معدل حقن غاز مثالي قدره 020222 متر مكعب قياسي في اليوم، مما أدى إلى زيادة ملحوظة في معدل إنتاج النفط بمقدار 78.5 متر مكعب في الساعة. بالإضافة إلى تعديل معدل حقن الغاز، تقترح الدراسة تحسينات أخرى تشمل تغيير قطر الأنبوب الداخلي)التجويف(وتعديلات في إعدادات الخانق (Choke) لتحسين أداء البئر بشكل أكبر.

الكلمات المفتاحية : تحليل العقد، تحسين الرفع بالغاز، الرفع الصناعي، برنامج PIPESIM ، حقل حاسي مسعود، انخفاض ضغط المكمن، أداء الجريان الداخلي، أداء الجريان الخارجي .

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Symbols

- AOF: Absolute Open Flow.
- BU: Build Up.
- DST: Drill Stem Test.
- PI: Productivity Index.
- IPR: Inflow Performance Relationship.
- VLP: Vertical lift performance.
- GLR: Gas Liquid Ratio.
- GOR: Gas Oil Ratio.
- PIPESIM: Pipeline Simulator.

- PVT: Pressure, Volume, Temperature.
- PFD: Dynamic bottom pressure.
- PFS: Static bottom pressure.
- ID: Interior diameter.
- ED: exterior diameter.
- CCE: Concentric.
- RMS: Root Mean Squared.
- API: density.
- d: Density.
- D: Tubing inside diameter (mm).
- PI: Productivity index (bbl/d*psi).
- Pb: Bubble pressure (bar).
- Pg: Reservoir pressure (bar).
- Q: Product flow rate (bbl/day).
- Qmax: Maximum flow rate (bbl/d).
- Qg: Gas flow rate (m3/day).

General Introduction

Gas lift is a fundamental artificial lift technique primarily employed to boost oil production from low-pressure reservoirs. It works by continuously injecting pressurized gas into the bottom of the well, supplementing the natural reservoir energy. The injected gas enhances fluid flow to the surface through several mechanisms, including the reduction of hydrostatic pressure due to decreased fluid density, gas expansion, and fluid displacement.

Gas lift is widely preferred among artificial lift methods, especially when injection gas is readily available. It offers several advantages over conventional systems such as rod pumps, including lower operational costs, ease of implementation, adaptability to varying well conditions, minimal maintenance, and the potential to maximize liquid production.

The core objective of gas lift is to reduce bottomhole pressure (BHP) and lift reservoir fluids to the surface, thereby creating a significant pressure differential between the reservoir and the wellbore. Lowering the BHP through gas injection decreases the density of the fluid column, which facilitates a higher production rate. However, excessive gas injection may lead to gas slippage—where gas ascends faster than the liquid—resulting in increased BHP and reduced oil output.

Therefore, determining the optimal gas injection rate and depth is crucial for maximizing oil recovery. This optimization is typically visualized using continuous gas lift performance curves.

An efficient gas lift design involves the careful optimization of variables such as tubing diameter, choke size, and gas injection rate to balance pressure availability and gas utilization. Accurate estimation of pressure drops during multiphase flow within the well is essential, as it significantly affects gas lift performance and efficiency—a challenge often addressed through detailed flow modeling.

Previous studies have evaluated widely used pressure drop correlations (e.g., Hagedorn and Brown, Duns and Ros, Orkiszewski) against real-world multiphase data from various wells. Among these, it is considered for evaluation in the present study to ensure a reliable and optimized gas lift design and operation.

Nodal analysis is a key methodology used to assess well performance, diagnose production issues, and enhance productivity. In this study, we highlight the application of nodal analysis in modeling the production system and forecasting improvement scenarios.

By applying this method to the ONM112 well in the Hassi Messaoud field, we evaluated the economic feasibility of activating gas lift. The results were as follows:

- Optimal gas injection rate (Qg): 20,000 sm^3/day
- Corresponding oil production rate (Qoil): 140.88 sm^3/day
- Initial oil production rate (Qoil): 0 sm^3/day
- Optimal injection depth : 3244.67m
- Choke diameter: 16mm
- CCE Out diameter: 1.66 inches

To this end, this study is organized as follows: The first chapter is devoted to general information on gas lift, the second chapter presents the gas lift at in HMD region. the third chapter presents the Nodal Analysis, The last chapter is a study of ONM112 well .

Chapter 1

Chapter 1: Generalities on gas lift

1.1 Introduction

Gas lift is an artificial lifting method that uses an external source of high-pressure gas to supplement formation gas to lift fluids from the well. Activation may be necessary from the beginning of exploitation if the reservoir lacks sufficient energy to transport fluids from the bottom to the treatment facilities or if the well's productivity index is too low. Globally, activation is primarily performed using two methods:

1. Gas lift.
2. Mechanical lifting through pumping

Artificial Lift It is a technique employed to enhance the productivity of wells experiencing low reservoir pressure and/or containing heavy fluids (such as water or heavy oil). This method facilitates the flow of fluids to the surface by either injecting a lighter fluid (like gas) into the well stream at depth or by installing a downhole pumping system, (ESP). the type of artificial lift available are illustrated in figure 1.1

Types Of Artificial lift:

- Sucker Rods Pumps
- Hydraulic Pumps
- Electric Submersible Pump (ESP)

- Gas Lift
- Progressing Cavity Pump (PCP). . . .other types, see Figure 1.1

[2].

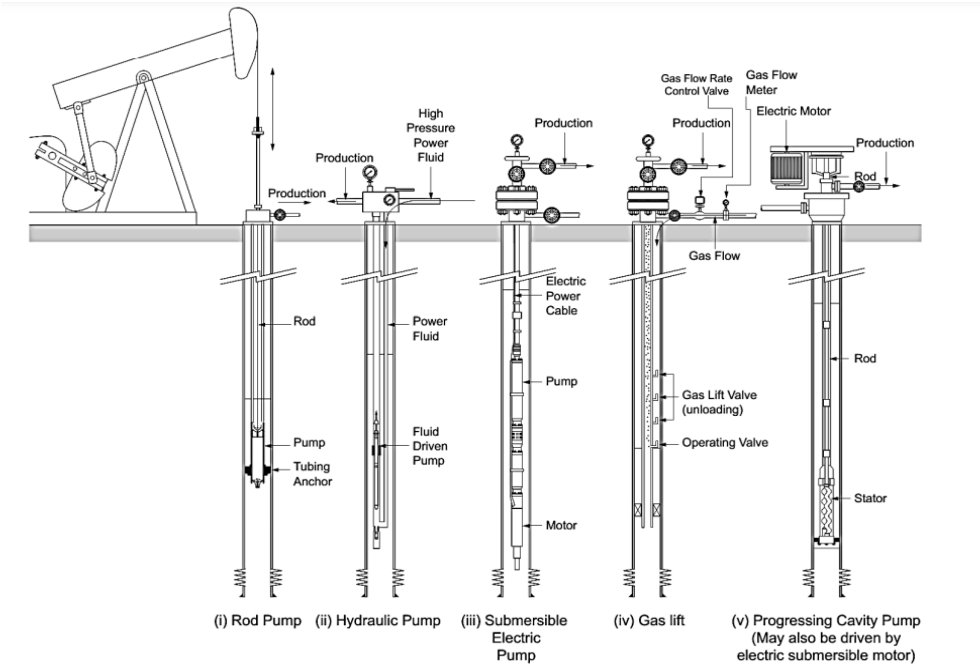

Figure 1.1: Types Of Artificial lift

In this chapter, we will focus on well activation using the gas lift technique.

1.2 The Gas lift

It is the most widespread and effective activation method in the world and its principle is based on lightening the hydrostatic column by injecting gas below the dynamic level of the liquid through well-placed valves or a small concentric tube provided for this purpose.

1.2.1 Gas Lift Systems

Gas lift is an artificial lift method that uses external high-pressure gas to enhance formation gas, reducing bottom-hole pressure and lifting well fluids. The key factors in choosing a gas lift system for a well, group of wells, or an entire field are gas availability and compression costs. Gas lift is ideal for wells with access to suitable high-pressure gas, which may come from gas compressors (used for injection or boosting) or high-pressure gas wells. Since compression costs are significantly higher than subsurface equipment costs, gas lift should be prioritized when sufficient high-pressure gas is available. It is a viable method for depleting most wells, especially with the widespread use of reservoir pressure maintenance programs in major oil fields. [3].

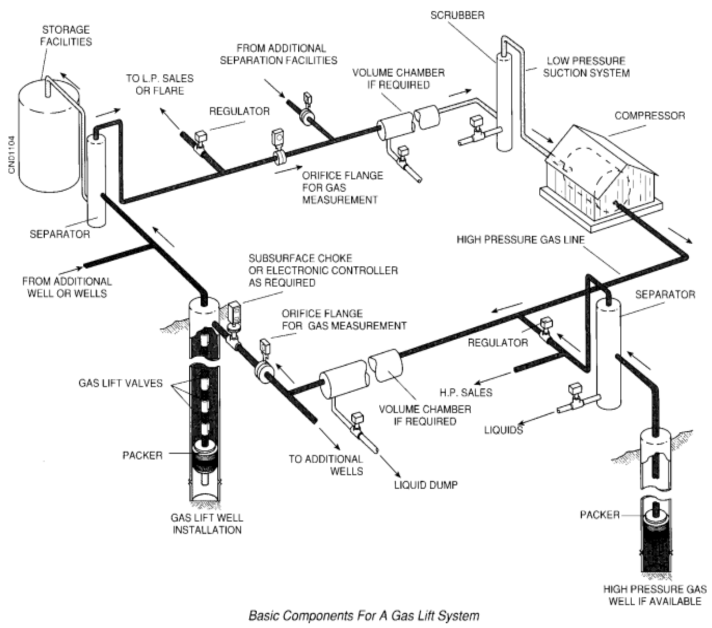

Figure 1.2: Basic components for gas lift systems

1.2.2 The principle of gas lift

The principle of gas lift is to inject gas to lighten the column of fluid contained in the tubing. As if we were adding power at the bottom of the well to help the reservoir send the effluent to the separator, see Figure1.3 . The amount of gas to be injected must not exceed a certain limit, this is the optimal GLRT.

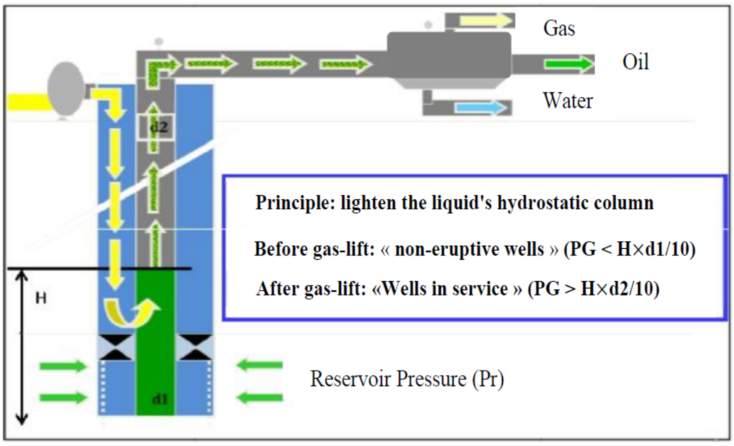

Figure 1.3: The gas lift principle [1].

1.2.3 Types of gas lift

Classification according to injection method

1. Gas-lift continues: This gas lift mode consists of injecting gas in a permanent or continuous manner, with a well-defined flow rate and pressure, as well as a depth which ensures the lightening of the production column in a manner which allows the reservoir effluent to rise to the surface.

2. Intermittent gas lift: This process is temporarily achieved by injecting a specific volume of pressurized gas at a high flow rate into the lower section of the production column, with the goal of pushing the contained fluid upwards. As the pressure in the lower section decreases, the fluid starts to move, and this cycle continues as the gas forces the fluid upward repeatedly. see Figure 1.4

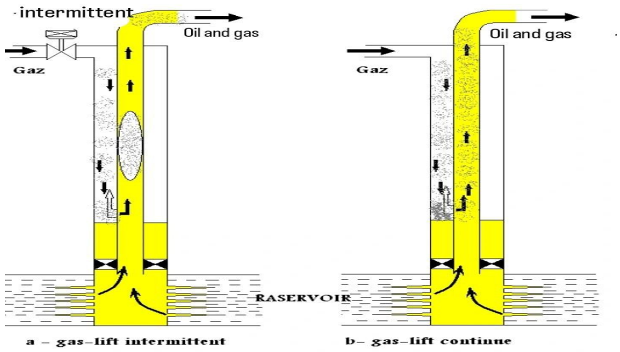

Figure 1.4: Continuous and intermittent gas-lift

Classification according to completion

1. Direct gas lift: In this case, gas injection occurs through the annulus, while production takes place through the tubing. This is the most commonly used and widespread method, as it allows for better optimization and management of the equipment, as well as easier intervention operations.

2. Indirect gas lift: In this case the injection method and production differs from the previous one. There are several techniques which are the following:

- Production by Casing and injection by Tubing: This technique is suitable for larger injection flow rate. These latter cases have serious defects such as: It is possible to take measurements on the effluent side. Requires a very The design of the equipment is very special. Not suitable for intermittent gas lift

- large Concentric tubing: Gas injection is through a concentric (macaroni) down into the Tubing, usually from a Snnubing operation, and production is through the tubing macaroni annulus, this method is better suited to larger injection flow rates and completions over 4"

- Parallel gas lift: This production method is for double completions, it has the same drawbacks as the previous one at the level of the implementation of the completion, the gas is injected into the tubing while second product, it is used in the case where The injection gas corrodes the casing. Production stopped at one of the levels where their tubing was converted. as a lift gas injector.

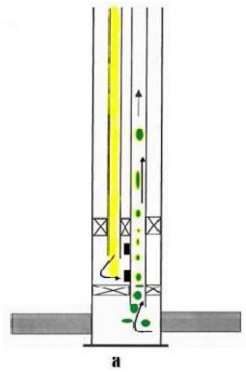

Figure 1.5: Gas-lift in concentric and parallel tubing

- Double gas lift: For multiple completions where two levels are to be exploited separately, the problem with this type of gas lift lies in the bulk, especially at the valve level, see the Figure 1.6 .

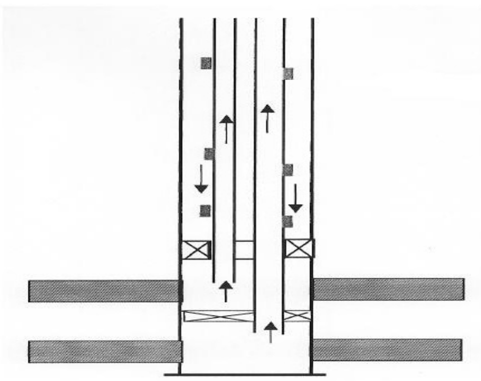

Figure 1.6: Completion of the double gas-lift

- Auto gas-lift: This type of gas lift represents a very special case, since it is linked to the type of completion and the nature of the reservoir (existence of a gas Cap), in this case the source of gas for injection is underground, perforations at the level of the gas Cap zone at the lainer level allow the flow of gas into the annular space, and consequently it will play the same role as the gas injected from the surface.

1.3 Gas-lift main parameters

1.3.1 Wellhead pressure

The lower the head pressure, the less gas is needed to produce the same amount of fluid. In addition, a low volume of injected gas allows for unobstructed surface installations, thereby reducing the pressure of the collections. .A low head pressure therefore improves the efficiency of the well and that of neighboring wells. It follows that gas-lift wells must never be 'dusted' at the wellhead. .A rule of thumb says that gas requirements are halved when wellhead pressure is halved.

1.3.2 Injected gas pressure

The pressure of the injected gas affects the number of relief valves. Thus, a high pressure can allow operation without a single point relief valve, which greatly simplifies the design, operation and maintenance of the well. When the available pressure is low, it is very useful to be able to increase it for a few hours from 10 to 15 bars to start the well (To Kick Off The Well). Likewise, it is very important to know whether the current gas pressure will not drop over time, making it impossible to restart a well.

1.3.3 Important IP and SKIN effect

The productivity of a well depends directly on the draw-down and therefore on the bottom-hole pressure in flow. Gas-lift activation reduces this pressure as do all activation methods. The effect is obvious in wells with large IPs where gas-lift brings spectacular flow rates. The damage to the first few centimetres of the tank is called the Skin effect. .The Skin effect has the direct effect of reducing the IP and must be combated by one of the many known processes such as acidification, re-perforation, etc. A well with a reduced IP requires a greater quantity of gas.

1.3.4 Gas injection depth

The deeper the injection point, the more efficient the injected gas. A deep injection point provides a very significant improvement in well production, especially for high IP wells.

Similarly, a significant portion of a well's possible production can be lost if gas is injected from a leaking relief valve instead of the operating one. Some completions are equipped with a packer with a bypass to allow the gas to descend as far as possible.

1.3.5 Water percentage

The percentage of water must be determined before injecting gas lift [4].

1.4 Advantages and limitations of gas lift

1.4.1 Advantages of Gas Lift

In terms of production rate ranges and depth of lift, the gas lift system is flexible and can rarely be matched by other artificial lift methods if required injection gas pressure and volume are existed. Gas lift is one of the most flexible artificial lift techniques which even unappropriated design will still lift some fluid. Highly deviated wells with high formation GLR and sand production are good candidates for gas lift when artificial lift is needed.

- Well suited for medium to high flow rates.
- Well suited for wells with good IP and relatively high bottomhole pressure
- Applicable for wells with relatively high GLR
- Single well equipment and cable-retrievable gas-lift valves: possibility of modifying operating conditions without having to raise the tubing.
- Possibility of injecting an additive (corrosion inhibitor for example) at the same time as the gas.
- Adaptation on deviated wells: current reliability of gas lift equipment on wells with a deviation reaching 50°.

1.4.2 Limitations of Gas Lift

Large well spacing for onshore wells and limited offshore platforms space for compressors may restrict the gas lift application. Gas lift is rarely applicable to single well installation and not appropriate for widely-spaced wells due to the difficulty of locating the power system centrally. Gas lift is not the option for viscous crude oil, super-saturated brine or emulsion fluid. In addition. the gas lift system does not work well for old casing wells, or long flow lines with small inside diameter (ID). gas lift process is limited to the BHP and fluid properties such as scale formation, existence of paraffin and corrosion because these properties may increase the friction in the tubular

- Gas volumes may be excessive for wells with a high percentage of water
- Not applicable in a casing in poor condition.
- Requires treatment in case of formation of hydrates, it will be necessary to treat the gas by dehydration.
- Its effectiveness is sometimes low compared to that of other activation techniques
- If the gas is corrosive, it must either be treated or completions installed special steels. Which increases the cost of investment.[5]

1.5 Use or Application of Gas Lift

- Putting non-eruptive wells into production: The primary goal of gas lift is well activation, achieved by injecting gas to reduce the hydrostatic column, lowering bottom-hole pressure, and enabling effluent flow up the tubing.
- Increase in flow rate: Gas lift boosts well production beyond natural flow, providing a solution for wells with declining pressure that can still produce without activation.
- Starting up eruptive wells: Sometimes, even an eruptive well may not restart after shutdown and requires activation to regain its flow. If mandrels were installed initially, high-pressure gas can be used to restart the well
- (injector clean up): Injection wells require periodic unloading and production to clean perforations and remove particle accumulate . With a high-pressure gas source[6].

1.6 Gas lift equipment

The purpose of the gas lift equipment is to ensure the circulation of surface gas towards the Tubing, to lighten it and allow the effluent to rise to the surface. So, it is necessary to have equipment on the surface and at the bottom. For example, on the surface, if the pressure is not sufficient, it is necessary to compress the gas injected by a compressor. In practice, it is necessary to have orifices for the injection of gas, these orifices are called valves. this equipment on the bottom and on the surface. see the Table 1.2 [7].

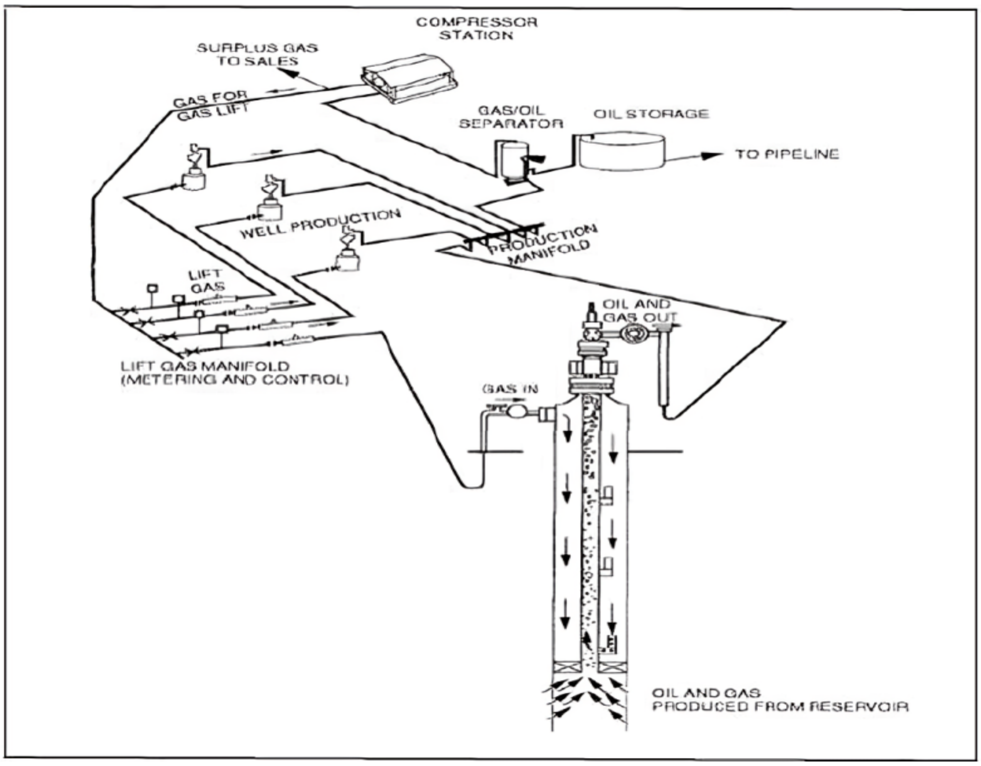

Figure 1.7: Gas lift equipment

Investment	**Equipment**
Surface	• **Compression equipment**: compresses the gas arriving from the separation station before it is sent to the well for injection. • **HP Distribution Network**: It is a collection of several pipes that carry high pressure gas to the wells that are connected to its network. • **Measuring and control equipment**: which are, the pressure gauge, the thermometer for the temperature, the nozzles for manual adjustment of the flow, the DANIEL orifice and the BARTON indicator for measuring the flow. • **BP distribution network**: This network carries gas in the low pressure direction, which starts from the wellhead to the separation station after, the storage for oil and the compression and dehydration station for gas. • **Dehydration equipment**: to eliminate the water that comes from the coming of the gas, because it causes hydrates. • **Inter transmitter**: suitable for intermittent gaslift, it is for adjusting the periodicity and duration of injection.
Bottom	• **The chucks**: it is an architecture placed in the tubing to allow the gas injection valve to be carried without affecting the diameter of the tubing. There are three types: conventional mandrels, side pocket mandrels, mandrels with concentric valve. • **Check valve**:to prevent fluid from flowing back into the formation • **Tubing spool**:equipped at its base with an insulating seal ensures that the pressurized annular ring cate any annot credanger to the last casing • **Ring safety**:It ensures the safety of the annulus where the gas volume is significant • **Injection valves**:are the most important elements, its role and the injection of gas from the annulus to the tubing.

Table 1.1: Surface and bottom equipmets

Chapter 2

Chapter 2: The gas lift at in HMD region

2.1 Introduction

In the HMD region, the majority of wells are equipped with continuous gas-lift, the aim of which is to improve productivity due to pressure drop. In this chapter we will see the completions and the properties of gas-lift in HMD region.

2.2 Presentation of Hassi Messaoud field

The Hassi-Messaoud region is characterized by a very strong oil industry, located in the north of the Algerian Sahara, it is one of the most complex oil fields in the world and the largest in Algeria with a total area of approximately 2000 km^2. During geological history, this deposit underwent intense tectonic evolution during its burial until the deposit took on its current form. Significant investments have been made, and more will be made in the future to extract the maximum amount of oil, and thus increase the final recovery.

2.2.1 Geographic location

It is located in the north-east of the Algerian Sahara, on the edge of the great eastern erg at approximately 850 km southeast of Algiers and 350 km from the Tunisian border.

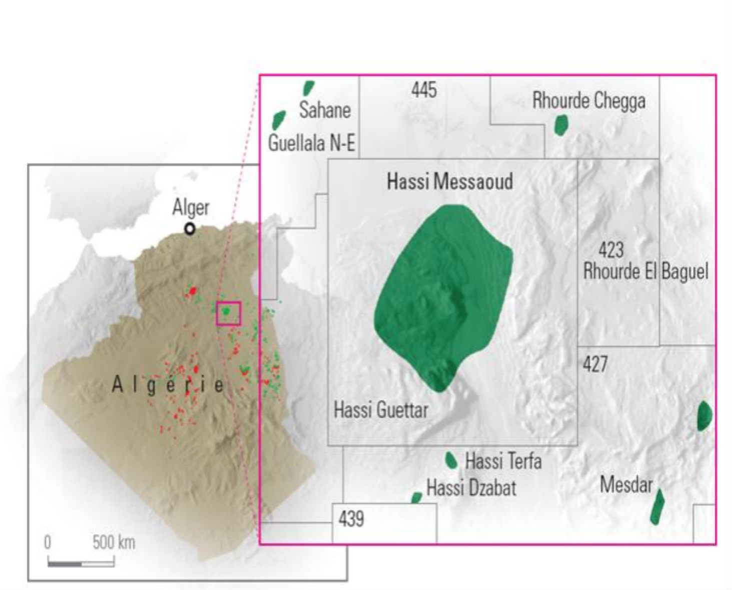

Figure 2.1: Location of Hassi Massoud.

- In LAMBERT coordinates: X=790,000 – 840,000 East;Y= 110,000 – 150,000 North

2.2.2 Geological structure

The structural image of Hassi-Messaoud is highly complex to analyze and difficult to define due to its dimensions and tectonic phenomena, and especially the interference between its structure itself and the Hercynian erosion that is superimposed on the depositional conditions of the Cambro-Ordovician sandstone [8]. Hassi-Messaoud field occupies the central part of the Triassic province. In terms of surface area and reserves, it is the largest oil field in Algeria, covering an area of nearly 2500 km^2. It is bounded as follows: to the northwest by the Ouargla fields: Guellala, Ben Kahla, and Haoud Berkaoui.

- To the southwest by the fields of El Gassi, Zotti, and El Agreb. .
- To the southeast by the fields of Rhourde El Baguel and Mesdar. Geologically, It is delimited as follows: to the west by Oued Mya depression, to the south by Amguid El-Biod high, to the north by Djammâa-Touggert structure [1] .

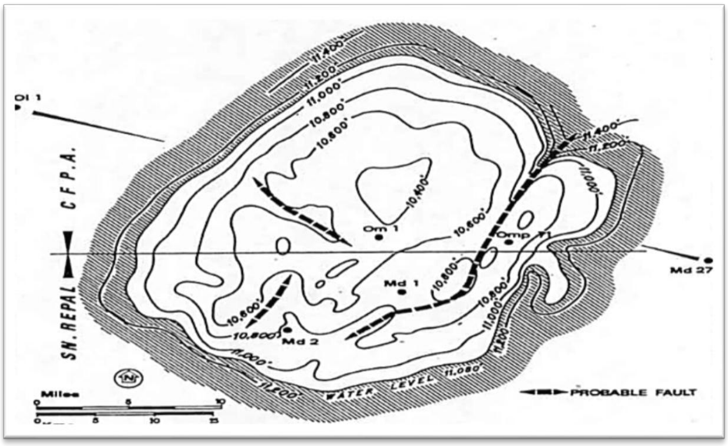

Figure 2.2: Geological structure of the Hassi-Messaoud field

2.2.3 Field history

Hassi-Messaoud oil field was discovered by two French companies, CFPA (Compagnie Française des Pétroles d'Algérie) and SN-REPAL (Société Nationale de Recherche Pétrolière en Algérie). In 1946, SN-REPAL commenced its exploration activities across the Sahara, and three years later, it initiated geophysical prospecting through gravimetric reconnaissance. On January 15, 1956, the first drilling, known as MD1 (Messaoud1), was completed. This drilling revealed Cambrian sandstones capable of oil production at a depth of 3338 meters. Subsequently, on May 16 of the same year, at a distance of 7.5 kilometers north of MD1, a second well named OM1 was drilled in continuation by CFPA. From 1959 to 1964, a total of 153 wells were drilled and put into operation[1].

2.3 The gas lift at HMD

2.3.1 History of the gas lift in HMD

By the 1980s, the need for artificial lift technologies became evident to maintain and enhance production. Among the various options, gas lift was selected for its suitability in handling high-temperature, deep wells, and large production volumes characteristic of the HMD reservoir. The first gas lift systems were introduced in the mid-1980s, initially in selected wells where reservoir pressure had dropped significantly. Over the years, the use of continuous gas lift and, in some cases, intermittent gas lift expanded across the field as a reliable method to support aging wells [9].

2.3.2 The purpose of the gas lift at HMD

The operation of gas lift activated wells in HMD fields aims to improve production for two necessary reasons: the reservoir pressure has reached values that allow the wells to be more eruptive. This results in a very large mark to produce and the nitrogen start is very expensive it was necessary to inject water to restore the tank and to increase the final recovery. This production technique allows us to:

- Reduce the fluid gradient.
- Lift the fluid that does not have enough strength to reach the surface.
- Activate wells that are still eruptive but at low pressure. The special feature of the HMD field is the availability of gas for injection and gas lift, the gas produced will subsequently be treated, compressed in compression stations and returned to the wells for pressure maintenance or gas lift

2.3.3 Source of gas lift in HMD

In the Hassi Messaoud (HMD) oil field in Algeria, gas lift operations are supported by gas sourced from the field's own substantial natural gas reserves. As of 2021, the field had remaining recoverable gas reserves estimated at approximately 44,156.59 million cubic meters . This internal sourcing enables efficient and continuous gas lift operations across the field [10]. The Hassi Messaoud field, discovered in 1956 and operational since 1958, is one of Algeria's largest oil fields. It comprises over 1,100 production wells, with approximately half utilizing continuous gas lift systems employing concentric (CCE) strings . This method involves injecting lift gas through the CCE string while production flows through the annulus between the CCE string and the tubing. The availability of substantial natural gas reserves within the field facilitates the implementation of such gas lift techniques [11]. Additionally, intermittent gas lift (IGL) has been employed in certain wells, particularly those with high gas/oil ratios (GOR), to mitigate hydrate formation and reduce flaring .

This approach further underscores the field's reliance on its own gas production to optimize oil recovery processes [12].

ZCINA Gas Processing Complex

The ZCINA (Zone de Compression et d'Injection du Nord d'Hassi Messaoud) complex is a significant gas processing facility located in Hassi Messaoud, Ouargla Province, Algeria. Operated by Sonatrach, Algeria's national oil and gas company, the complex plays a crucial role in processing associated gas from nearby oil fields[13]. through this complex, the reinjected gas—comprising the following components—is transported back.

The following table shows the different compositions of the gas lift at HMD, with these molar fractions.

Table 2.1: Gas-lift compositions at HMD

Constituents	N2	CO2	C1	C2	C3	i-C4	n-C4	i-C5	n-C5	C6	C7
Fr. Molar	3.6	0.71	66.29	24.05	4.66	0.20	0.43	0.03	–	–	–

Chapter 3

Chapter 3: Nodal Analysis

:

3.1 Introduction

A production well is drilled and completed to extract oil, gas, or water from a subsurface reservoir. It can be defined as a conduit between the reservoir and surface processing facilities. This connection is essential for transporting reservoir fluids to the surface. To assess and reduce the pressure losses in the production system during the extraction of these fluids, energy is required. This Production systems can be simple or contain many components in which pressure losses occur. Due to:

- Friction losses of the effluent on the walls of the tubing.
- The hydrostatic weight of the effluent (gas, water and oil) in the tubing.

a change in pressure drop in any level of this system can change the pressure drop behavior in all other levels. therefore the final design of a production system cannot be separated into reservoir performance and pipe system performance and treated independently; but must be analyzed entirely as a single unit. The method that allows to study and analyze a production system as a single unit is nodal analysis.

3.2 Concept of nodal analysis

Nodal Analysis is a tool for evaluating complete production systems (starting with reservoir static pressure and ending with the separator) and for predicting flow rate. It is an optimization technique that can be used to analyze production problems and improve well performance. It has been used extensively in oil and gas fields since it was introduced by Gilbert in the 1950s. It consists of combining the reservoir's ability to produce fluids downhole with the tubing's ability to convey effluent to the surface. Practical applications of Gilbert's ideas are limited due to the restrictions of the methods available at that time Can be used to model the performance of individual system elements. Later the choice was wide with computational models available and the advent of computers that led to the re-emergence of Gilbert's ideas in the 1980s. The new contribution aimed at numerical simulation of the production system allows to optimize production (have a desired flow rate). The method of analyzing a production system was called "nodal analysis" by KE Brown, and this name has been generally accepted. [14].

3.3 The method of applying nodal analysis

System analysis or nodal analysis methods have been used to analyze the performance of systems consisting of several elements interacting with each other. The pressure drop in the system at any time will be the sum of Pressure drop in all components of the system (Figure 3.1) It should be noted that there are two pressures in the system that are not a function of flow. These are: Pr and Psep and/or the wellhead pressure, if the well is choke controlled.

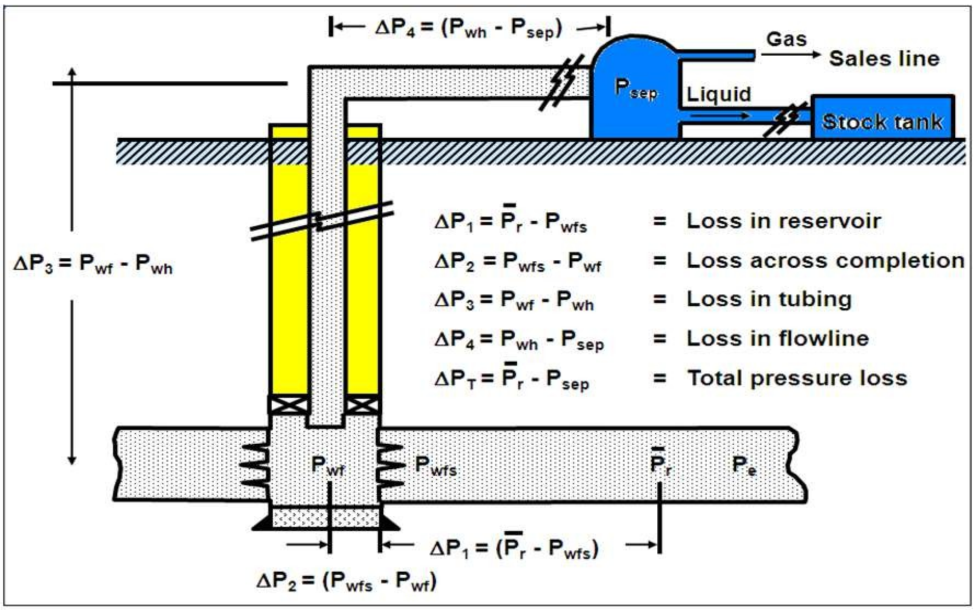

Figure 3.1: Pressure losses.

The selection and sizing of the various components of the production system is important because a change in pressure drop is followed by all other changes in pressure drop. The pressure drop along any component changes with the rate of production, i.e., it is not the amount of oil and gas flowing from the reservoir to the well that depends on the pressure drop in the system pipes, but it is the pressure loss in the pipe system that depends on the amount of fluid flowing through it. So how can we calculate pressure losses without knowing a flow rate value? This is the central question of nodal analysis. For this the nodal analysis based on the subdivision of the production system to elements. And nodes are placed in a section or segments which are defined by different equations or correlations. Figure 3.2 shows the locations of the various nodes. These nodes are classified as functional nodes when the difference between the pressure at that node and the pressure or flow response can be represented by some mathematical or physical function. The system can be subdivided as follows:

- Flow in the porous medium
- Completion (stimulation, perforation, and gravel pack).
- Flow in vertical or directed tubing (restriction, safety valve).
- Surface flow in collection networks (duse, pipes, vlves, etc.).

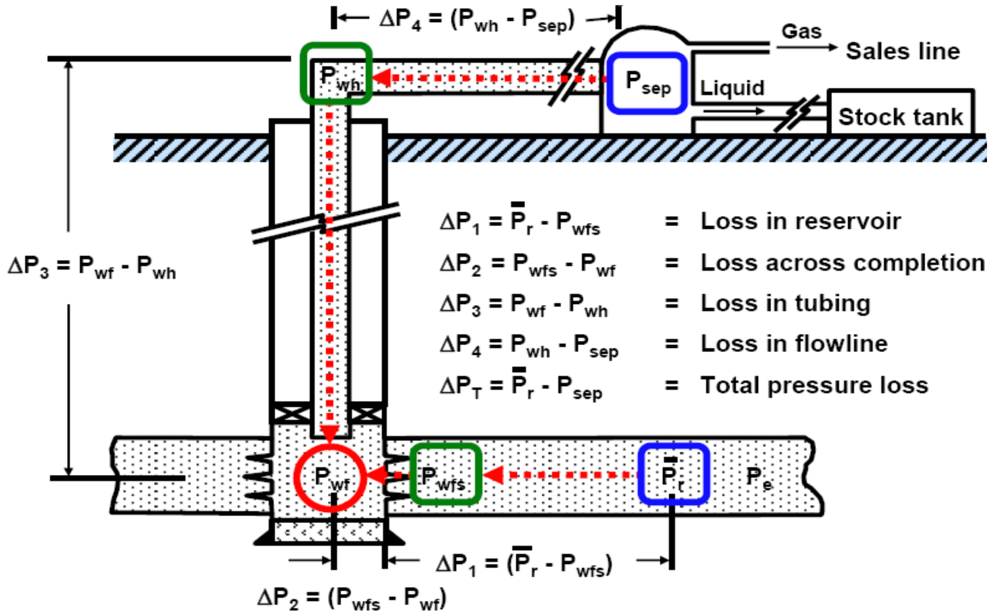

Figure 3.2: Simple position of the nodes in flow Equation

The process involves selecting a node in the well and dividing the system into that node. All components upstream of the node form the In flow section, while the Out flow section is composed of all elements downstream of the node. The relationship between the flow rate and pressure loss must be established for each element of the system. The flow rate through the system is determined once the following conditions are satisfied at the node:

- Incoming flow equals outgoing flow.
- only one pressure can exist.

Once the node is selected, the pressure at it is determined by:

- Inflow:

$$Pnode = Pr - Dp \tag{3.1}$$

- Outflow:

$$Pnode = Psep + Dp \tag{3.2}$$

The pressure drop across any component varies with flow rate q, a Expressing pressure as a function of flow rate gives two curves whose intersection will give points that satisfy the above two conditions; this is the operating point of the system.

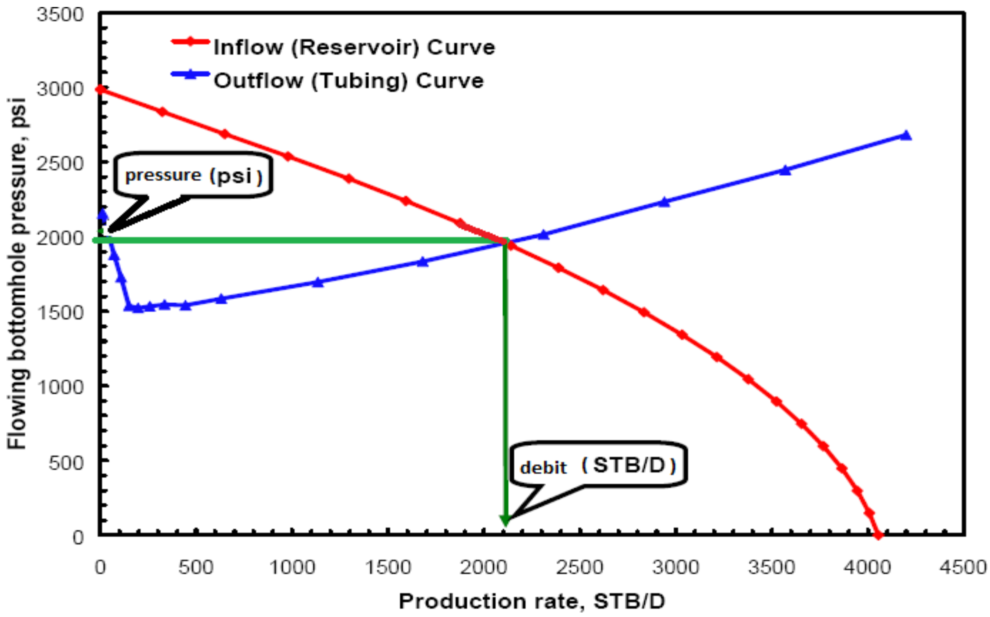

Figure 3.3: Operating point

The effect of the change in any component can be analyzed by recalculating the node pressure as a function of flow using the new characteristics of the component. If the change is in the ascending components, the curve Out flow does not change. With the change of one of the two curves, we will have another operating point i.e. a new flow capacity even if the fixed pressures change due to exhaustion or a change in separation conditions [15].

3.3.1 Node determination

In the present state of knowledge, there is no general law that can accurately determine the pressure losses associated with two-phase flow; however, there are some equations or correlations that give approximate results. The nodal analysis is derived from the node, in the production system. A node is any point between the reservoir and the separator, where pressure can be calculated as a function of flow.

3.3.2 Operating point:

Nodal analysis is a method employed to evaluate the performance of a production system, which consists of several interrelated components. This process involves selecting a node within the well and partitioning the system at this point. The operational point of a well is determined by the flow from the reservoir to the well, which is contingent on the pressure gradient between the reservoir and the bottomhole (Pr-Pwf), also known as drawdown.

This relationship is graphically depicted by the Inlet Performance Relationship (IPR) curve. While the IPR illustrates the reservoir's capacity to deliver to the bottomhole, the Vertical Lift Performance Relationship (VLP) signifies the well's ability to deliver to the surface [1].

3.4 Implemention 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: [16]

1. Selecting optimal tubing dimensions.
2. Choosing the right surface collection setup.
3. Investigating abnormal flow restrictions in existing systems
4. Evaluating well stimulation techniques.
5. Analyzing the impact of perforation density

3.5 Equations and correlations for calculating pressure losses

3.5.1 Pressure loss in the porous medium (IPR)

The flow to the well depends on the drawdown or pressure drop in the reservoir. The relationship between flow rate and pressure drop in the porous medium can be very complex and depends on several parameters, such as rock properties, fluid properties, flow regime, rock saturation by fluid, fluid compressibility, formation condition (damaged or stimulated) etc. The flow of fluid from the reservoir to the well is called by Gilbert "in flow performance"; and the representation of the flow rate as a function of dynamic bottomhole pressure is called "In flow performance Relationship" or IPR.

Darcy's equation

To calculate the pressure drop produced in a reservoir, an equation that expresses the energy or pressure losses due to shear or viscous friction forces as a function of velocity or flow rate is required. Although the form of the equation can be quite different for different types of fluids, the basic equation is Darcy's law. This equation proposed in 1856 by Henry Darcy relates the apparent fluid velocity to the pressure drop across the filter, Darcy's law is expressed:

$$V = -\frac{k\frac{dp}{dx}}{u} \tag{3.3}$$

- K: Permeability of the porous medium.
- v:Apparent fluid velocity.
- u: Viscosity of the medium.
- dP/dx:Pressure gradient in the direction of flow

[17]

IPR Correlations for Gas Wells

If all variables in the in flow equations could be calculated, the equations resulting from the integration of Darcy's law can be used to construct the IPRs. Unfortunately, there is very little information to adequately apply this equation. Therefore, empirical methods must be used to predict the inflow rate of a well, the most widely used to construct the IPR of a gas well, are presented in this section. Most of these methods require at least one stabilization test on a well, and some require multiple tests in which and must be measured. The most commonly used correlations for plotting the IPR of gas wells are: [18].

Jones Correlation: The Jones equation for gas is a modified form of the Darcy equation that takes into account pressure losses in laminar and turbulent flow, it isexpressed in the form :

$$(pr - pwf) = AQ^2 + BQ \tag{3.4}$$

Forcheimer correlation: This correlation expresses the IPR as a function of the pressure loss coefficients in turbulent flow and laminar flow :

$$(pr - pwf) = AQ^2 + BQ \tag{3.5}$$

back pressure:

$$Q = c(pr^2 - pwf^2)^n \tag{3.6}$$

C and N: It is the same form as the back pressure equation but it differs in the way it is obtaining the constants c and n:

$$Q = c(pr^2 - pwf^2)^n \tag{3.7}$$

3.5.2 Pressure losses in the tubing (Out flow)

The pressure loss equation for a multiphase flow is composed of three terms:

- The elevation term or the static term.
- The term friction
- The acceleration term
- Total pressure loss = friction loss + elevation loss + acceleration loss.

Single-phase vertical flow configuration:

Two-phase vertical flow configuration:

When two fluids with different physical properties flow simultaneously in a pipe, there is a wide range of possible flow patterns.

The distribution of each phase relative to the other in the pipe is the reference for which the model is established. Several models attempt to predict the flow pattern that may exist for different sets of conditions, and several different names have been given to these patterns, for reliability. Some head loss correlations rely on knowledge of the flow pattern. [19].

$$\frac{Q_o}{Q_{o(\max)}} = 1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2 \tag{3.8}$$

- Qo:flow rate corresponding to Pwf
- Qo(max): Maximum flow rate corresponding to zero dynamic pressure
- Pwf: The dynamic bottomhole pressure
- Pr: Appoximate reservoir pressure

The general energy equation:

The theoretical basis for most fluid flow equations is the general energy equation, this equation is an expression for the equilibrium or conservation of energy between two points in a system. The energy equation is first developed, using principles of thermodynamics, is modified to a pressure gradient equation form [20].

$$U_1' + P_1V_1 + \frac{m \cdot v_1^2}{2 \cdot g_c} + \frac{m \cdot g \cdot Z_1}{g_c} + q' + W_s' = U_2' + P_2V_2 + \frac{m \cdot v_2^2}{2 \cdot g_c} + \frac{m \cdot g \cdot Z_2}{g_c} \tag{3.9}$$

$$\left(\frac{dP}{dz}\right)_{\text{total}} = \left(\frac{dP}{dz}\right)_{\text{ele}} + \left(\frac{dP}{dz}\right)_{f} + \left(\frac{dP}{dz}\right)_{\text{acc}} \tag{3.10}$$

3.6 The software used to apply nodal analysis:

3.6.1 Overview of PIPESIM software

PIPESIM is an advanced production system performance analysis software developed by SCHLUMBERGER. It is utilized by production and reservoir engineers to accurately simulate and optimize the multiphase flow of oil, gas, and water through wells, pipelines, and surface facilities. The software supports informed decision-making and enhances the overall efficiency and reliability of production systems. The sensitivity calculations that PIPESIM provides allow existing designs to be optimized and the influence of future changes on the parameters of the system considered. By separating the modeling of each component of the production system, PIPESIM thus allows the user to verify each subsystem model through the matching function, PIPESIM ensures that the calculations are as accurate as possible. Once a system model has been calibrated to the actual measured well data, PIPESIM can be used with confidence to model the well in different scenarios and make advanced predictions of well and reservoir data [21].

3.6.2 Characteristics:

The PIPESIM simulator offers the industry's most comprehensive steady-state flow assurance workflows for front-end system design and production operations: [15].

- Complete steady-state flow assurance workflows
- Conversion tool for streamlined modeling of steady-state and dynamic flow assurance
- Visualization of consolidated results, including results from multiple simulations.
- Parallel network resolver to distribute computing processing to significantly improve performance.
- Continuous validation of the model

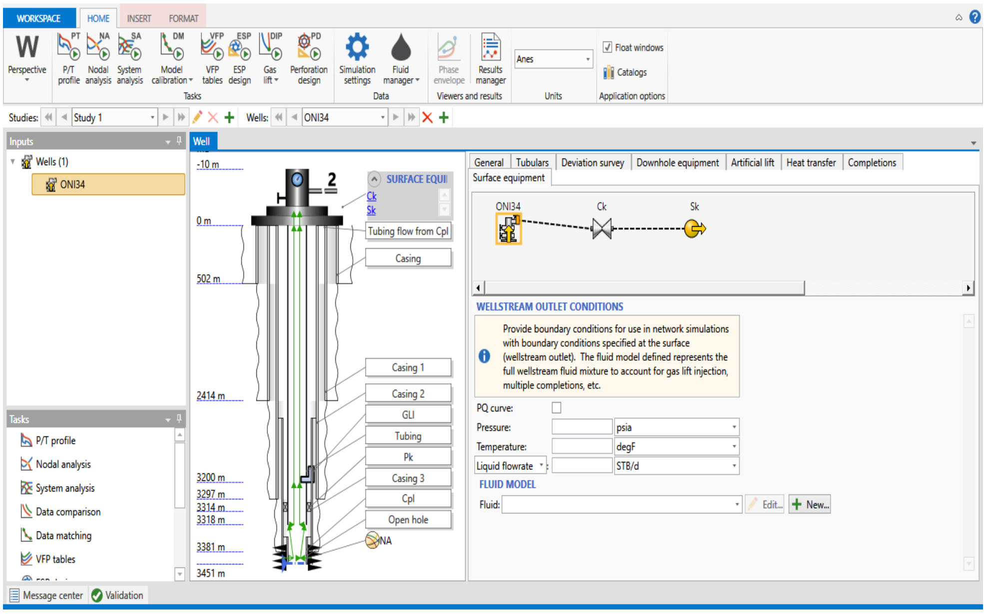

Figure 3.4: Software interface

3.7 Applications:

Engineers can ensure safe and efficient fluid transportation through the sizing of facilities, pipelines and recovery systems, effective liquid and solids management, and well and pipeline integrity

- Enables rapid construction of well models, with interactive schematics and graphical models
- Allows easy transition from a well layout to a network-centric layout through a simplified working environment
- Enables design and operation optimization by addressing potential throughput assurance challenges for the entire production system
- Accurate modeling of flow rates over the entire life cycle of a system.
- Provides comprehensive and sophisticated sensitivity analyses of the hydraulic system.

[15].

3.8 Conclusion

In summary, the maximum daily fluid production and the minimum flow pressure throughout the entire oil well production process should be predicted using numerical simulation or the future performance curve prediction method of the inflow performance relationship (IPR). This is done to optimize the completion parameters and tubing size using the nodal analysis method. This is the primary focus of the well completion engineer. For an oil or gas well already in production, the nodal analysis method is useful for effective and scientific production management.

Chapter 4

Chapter 4: Case Study

4.1 Introduction

In this chapter, we will examine the gas lift system with a focus on system design and production optimization in the well ONM112.

4.2 Well ONM112

4.2.1 Well selection

The choice depends on the well's problem, which involves the drop in well static pressure due to depletion over the well's lifestime.

4.2.2 Well ONM112 position

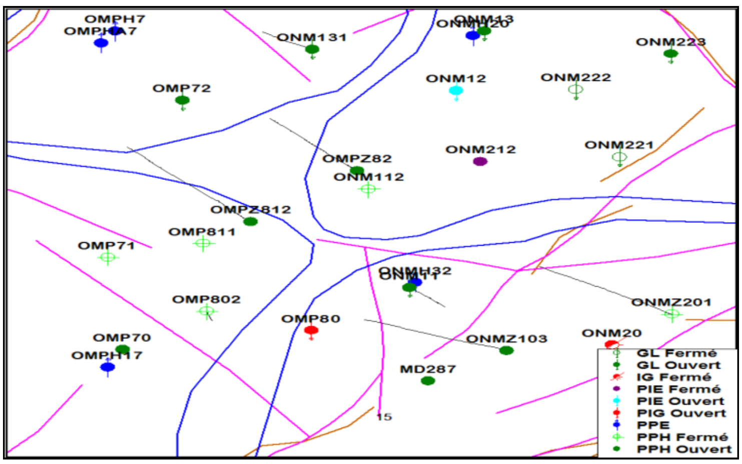

Figure 4.1: Position of Well ONM112

4.2.3 Well ONM112 History

ONM112 well drilled and completed on 15/08/1982 in 2”7/8 EU anchored, reservoir covered with a mixed liner 4”$\frac{1}{2}$ cemented x 5” Slotted Liner, The well started production with an average flow rate Qo 2m3/h (calculated flow rate) in January 1983; production was not stable and the well was closed for long periods (October 1984 – March 1989 / January 1990 – November 1992 and June 1995 – May 1997).

1. From 08/27 to 09/08/1998 Snubbing operation: CCE 1"315 descent:
   - Crown descent 64mm. Tope Sediments A 3438, 10 M. and cleaning with crude + nitrogen from 3438 to 3444, 30 m. (bottom).
   - CCE 1"315 downpipe and adjust shoe A 3430.87 MC/1.Vm. Screw in needles. Test OliVe A 5000 Psi
2. November 16 and 17, 2008: wire line operation (PFS pressure measurement):
   - Amerada descent JE ‘ 3410m DD: 09:42-10:17, remote JE from 3410m 15mn stages DR: 14:17-16:10.
   - Descent Caliber 22 mm ‘ 3420mcc.
3. 12/29/2009: wire line operation (PFS pressure measurement):
   - Descent Caliber 20 mm Top Bottom: 3446 mCC
4. From 03 to 06/10/2010 Operation Snubbing:
   - CCE 1"315 ascent (TD: 3444, 50m)
5. 06/28/2019: wire line operation: Control:
   - Descent Caliber 71 mm free. Rec/X: 3255mCC=3250.38mCT.
   - Descent Caliber 68 mm free. Rec/XN:3260mCC=3265.29 mCT.
   - Bailer 57mm downpipe pistoned to 3449mCC, reassembled to the day Sample

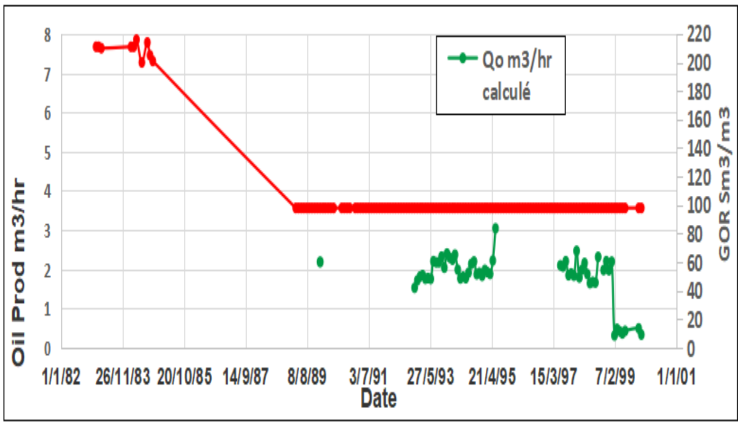

Figure 4.2: The well production profile (1) ONM112

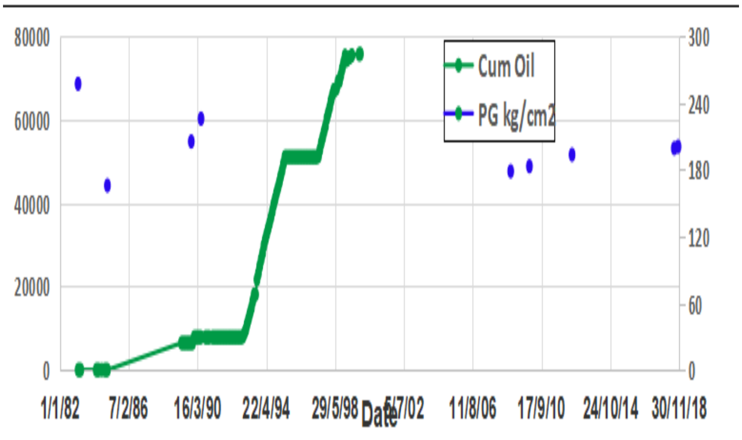

Figure 4.3: The well production profile (2) ONM112

Interpretation:

- The sharp initial decline followed by a plateau suggests that the well passed from a transient to a boundary-dominated flow regime.
- The GOR trend implies that gas production became less significant towards the later years, possibly due to reservoir depletion or shut-in of high GOR producing zones.
- Operational strategies during the stable period were likely aimed at maintaining oil production while controlling gas production.

4.2.4 Well testing ONM112

The well test ONM112 results were as follows:

Test	Date	PG (kg/cm²)	PFD (kg/cm²)	PT (kg/cm²)	Qoil (m³/h)	IP	HKP	HKL	HKL (Hw * Kyz)	Skin	Choke
DST	30/08/1982	257.5	227.02	57.5	6.04	0.252	297	37	0.24	9.5	-
PFS	18/02/1985	166	-	-	-	-	-	-	-	-	-
PFS	10/11/1986	187.23	-	-	-	-	-	-	-	-	-
PFS	20/02/1987	188.41	-	-	-	-	-	-	-	-	-
PFS	05/11/1989	205.63	-	-	-	-	-	-	-	-	-
PFS	22/06/1990	226.12	-	-	-	-	-	-	-	-	-
PFS	16/11/2008	178.78	-	-	-	-	-	-	-	-	-
PFS	29/12/2009	193.3	-	-	-	-	-	-	-	-	-
PFS	14/07/2012	199.72	-	-	-	-	-	-	-	-	-
PFS	18/08/2016	199.55	-	-	-	-	-	-	-	-	-
PFS	08/11/2018	201	-	1.6	-	-	-	-	-	-	-

Table 4.1: Well testing ONM112

The well ONM112 underwent a DST (Drill Stem Test) at 15/02/2025 after the completion of the Short Radius operation, and the results were as follows:

- Pg= 200 kg/cm2
- PFD= 179 kg/cm2
- PT= 33 kg/cm2
- Debit huile= 4.01 m3/h
- IP= 5.309
- Skin= 2.54
- Duse= 9.53

4.2.5 Well problematic

This well was drilled in 1982, and production from it initially proceeded successfully. Over time, however, the reservoir pressure began to decline, which gradually led to a decrease in production rates until the well eventually ceased production entirely. As a result, the well was shut in. Therefore, the engineers performed a short radius operation on the well to bring it back into production. Nitrogen(N2) injection was utilized, which successfully restored production. However, once the nitrogen injection was stopped, the well ceased production again. Accordingly, it was decided to implement gas lift technology to ensure continuous production from the well.

4.2.6 Current well status

Current well status: Well closed in December 1999 following Q null.

4.3 Optimization procedure

The optimization procedure for gas-lift wells involves a meticulous consideration of various factors governing the maximum flow rate attainable from the well. These factors include the inherent characteristics of the reservoir, as represented by the Inflow Performance Relationship (IPR), and the specific attributes of the installation, as encapsulated by the Vertical Lift Performance (VLP) characteristics. In the process of optimizing a gas-lift well, the primary objective is to ascertain the precise gas flow rate required for achieving peak production, denoted as the optimum flow rate. This optimal value is typically determined through the analysis of a production flow rate versus injection gas flow rate graph, commonly referred to as the Gas Lift Performance curve or GAUSSE curve. The GAUSSE curve delineates the point of optimum efficiency, beyond which any further augmentation in the injection flow rate results in a diminishing return, ultimately leading to a reduction in production output.

Hence, the aim is to construct the gas lift performance curve for each well earmarked for optimization. To achieve this objective, the following procedural steps will be adhered to:

4.3.1 Determination of the Optimal Production Rate of a Gas Lift Well

we will illustrate below the principle of the procedure used to calculate the optimal production rate of a gas lift well. We will plot the IPR (Inflow Performance Relationship) and VLP (Vertical Lift Performance) curves on the same graph. To do this, we will determine the corresponding dynamic bottomhole pressures for each flow rate The intersection of the IPR curve (representing the reservoir characteristics) and the TPC curve (representing the system performance) gives the operating flow rate of the well for the given GLR

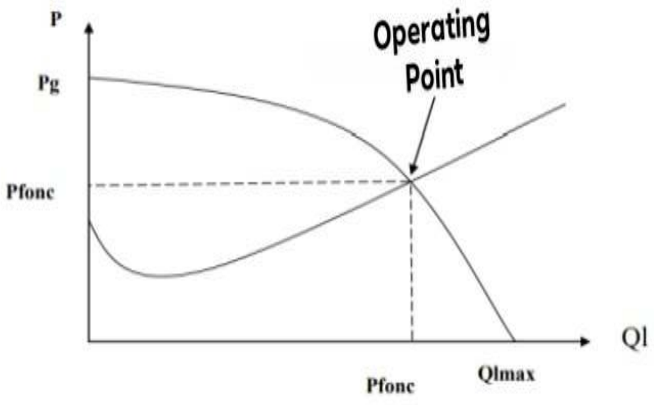

Figure 4.4: Inflow and Outflow Curves

4.3.2 Data required to use PIPESIM

Extracted from the DATA BANK are the outcomes of numerous tests and assessments conducted on the designated wells, alongside pertinent technical details pertinent to these wells. Specifically, the following data are essential:

- From gauging activities: oil flow rate, Gas-Oil Ratio (GOR), Head pressure, and choke diameter.
- From well tests (including build-up tests): Tank pressure and temperature, Dynamic bottom pressure, head pressure, productivity index, oil flow rate, and nozzle diameter.
- Derived from the data sheet related to well completion: specifications concerning well completion (tubing, casing, concentric), Measured Depth (MD), dimensions encompassing the Inside and outside diameter of tubing, and parameters pertaining to roughness.
- PVT (Pressure-Volume-Temperature) data: Dissolution Gas-Oil Ratio (Rs), bubble pressure, as well as the densities of oil and gas.

The program PIPESIM gives you various tools to control the wells parameters; this figure showcases a workshop space of the wells perspective.

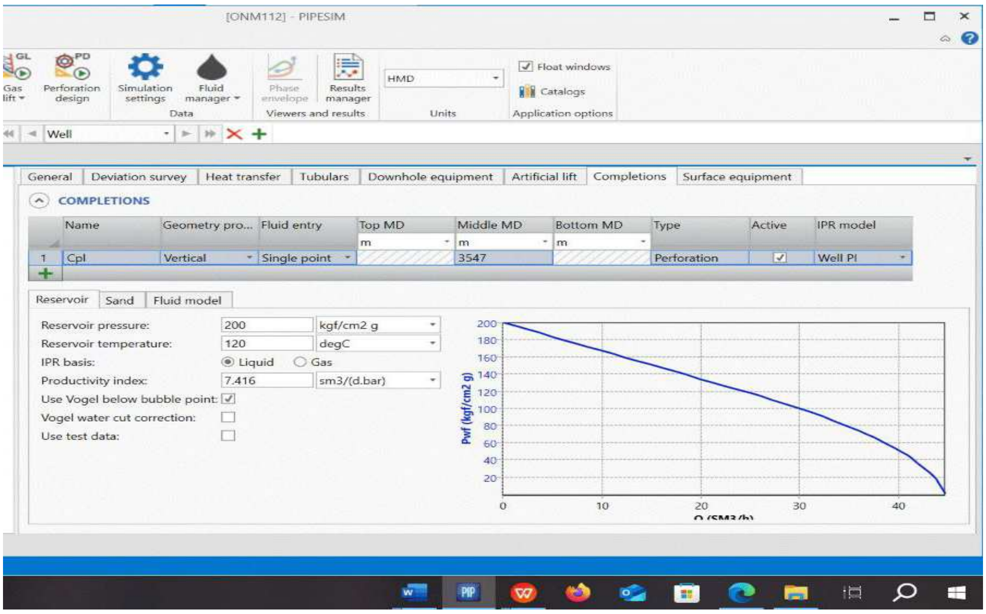

Figure 4.5: Completions parameters(ONM112)

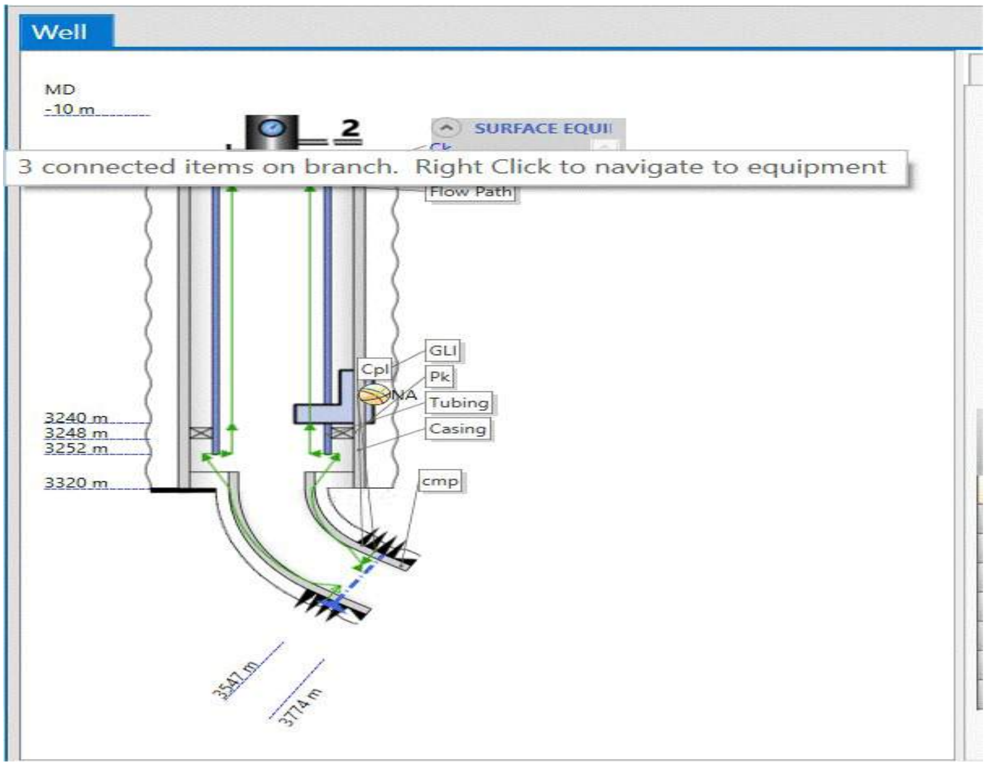

Figure 4.6: The depiction of well completion, as modeled by PIPESIM.(ONM112)

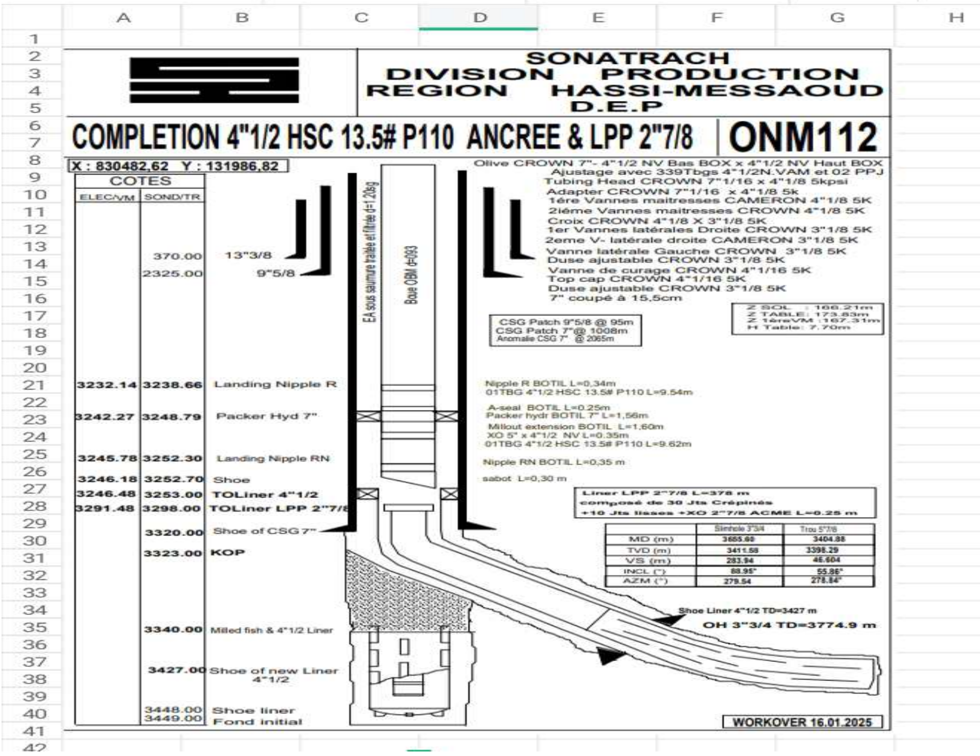

Figure 4.7: Well ONM112 completion

CASINGS/LINERS

	Section type	Name	From MD	To MD	ID	Wall thickness	Roughness
			m	m	in	in	in
1	Casing	Casing	0	3320	6.094	0.453	0.001
2	Liner	cmp	3298	3774	2.441	0.3743802	0.001

TUBINGS

	Name	To MD	ID	Wall thickness	Roughness
		m	in	in	in
1	Tubing	3252	3.92	0.29	0.001

Figure 4.8: Tubular parameters

4.3.3 Determination of RMS (Root Mean Squared) correlation

The deviation between the dynamic bottom pressure and the calculated values, expressed as a percentage for each correlation: RMS relations:

$$RMS_P = \frac{\sqrt{\sum_{i=1}^{nP}(P'i - Pi)^2}}{\sqrt{nP}} \tag{4.1}$$

$$RMS_T = \frac{\sqrt{\sum_{i=1}^{nT}(T'i - Ti)^2}}{\sqrt{nT}} \tag{4.2}$$

$$RMS_L = \frac{\sqrt{\sum_{i=1}^{nL}(L'i - Li)^2}}{\sqrt{nL}} \tag{4.3}$$

Where:

- RMSp = Root Mean Square (RMS) error calculated for pressure matching.
- P'i = Predicted pressure value for the i.th observation from the flow correlation.
- Pi = Measured or observed pressure value for the i.th observation.
- Np = Number of pressure observations.
- RMST = RMS error calculated for temperature matching.
- Ti = Predicted temperature value for the i.t observation from the heat transfer models.
- T'i = Measured or observed temperature value for the i.t observation.
- nT = Number of temperature observations.
- RMSL = RMS error calculated for liquid holdup matching.
- L'i = Predicted liquid holdup value.
- Li = Measured or observed liquid holdup value.
- nL = Number of liquid holdup observations.

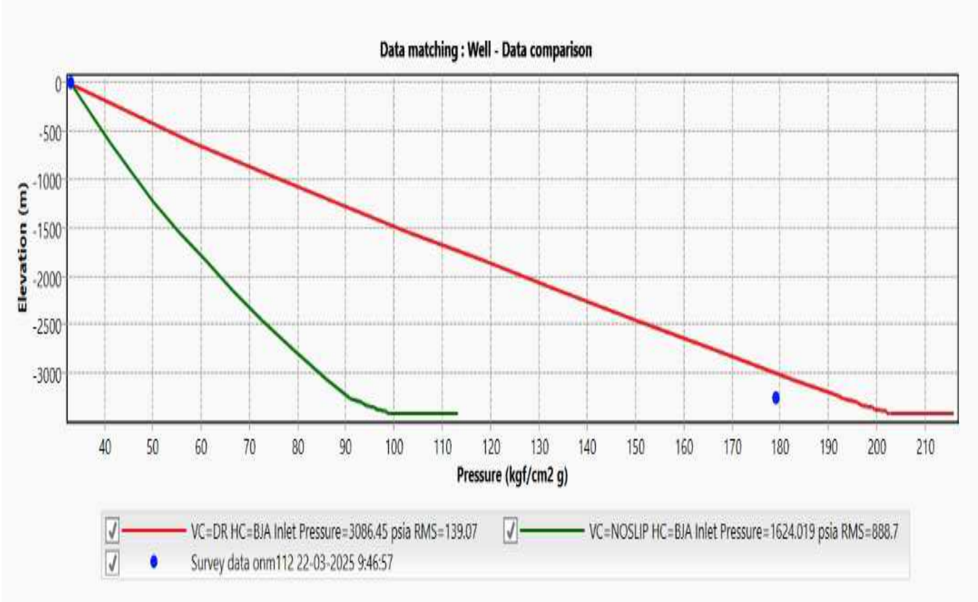

Figure 4.9: Multiphase flow correlation comparison sample well ONM112

The most suitable correlation is the one that provides pressure values close to the survey data.

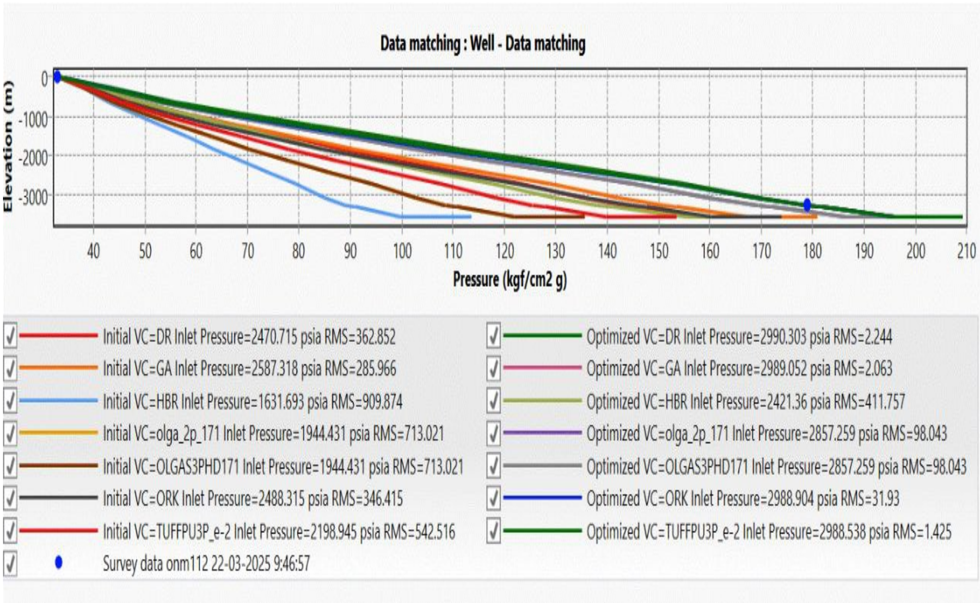

Figure 4.10: Well correlation matched graph.

The model was tuned for the most accurate multi-phase flow correlation and was used to handle the gas lift optimization tasks.

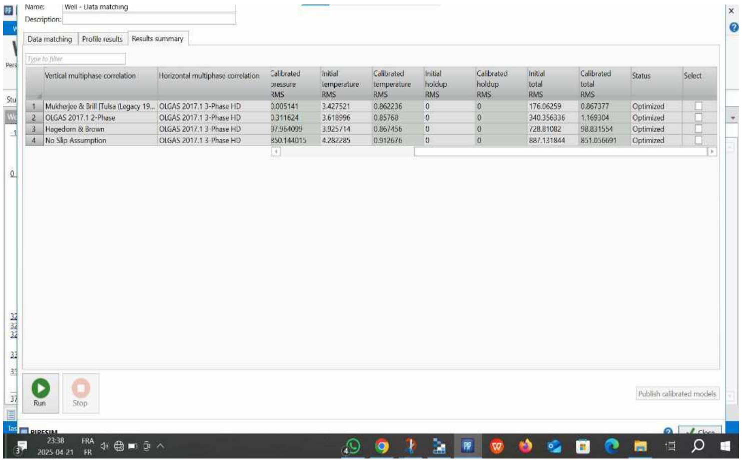

Figure 4.11: RMS Results Obtained by Data Matching.

CORRELATION	RMS
Mukherjee / Brill	0.867
OLGAS 2017.1.2-phase	1.169
No slip Assumption	851.056
Hagedorn & Brown	98.831

Table 4.2: Correlation RMS Values

4.4 Well performance

Well performance assessment involved the integration of build-up and gauging data derived from the ONM112 well into computational software for the determination of the system's operational state. The pertinent parameters included:

- Borehole temperature (T): 120°C
- Borehole pressure: 200 kg/cm^2
- Average oil density, as per API gravity: 45
- Gas density (dg): 0.73
- Water density (dw): 1.02
- Dissolution Gas-Oil Ratio (Rs): 128 m^3/m^3
- Bubble point pressure (Pb): 193.97 kg/cm^2

- Gas-Oil Ratio (GOR): In the context of PIPESIM modeling, Rs, representing the GOR in reservoir, was utilized. In this investigation, Rs was determined to be 128.

4.5 Latest well test (BU) matching:

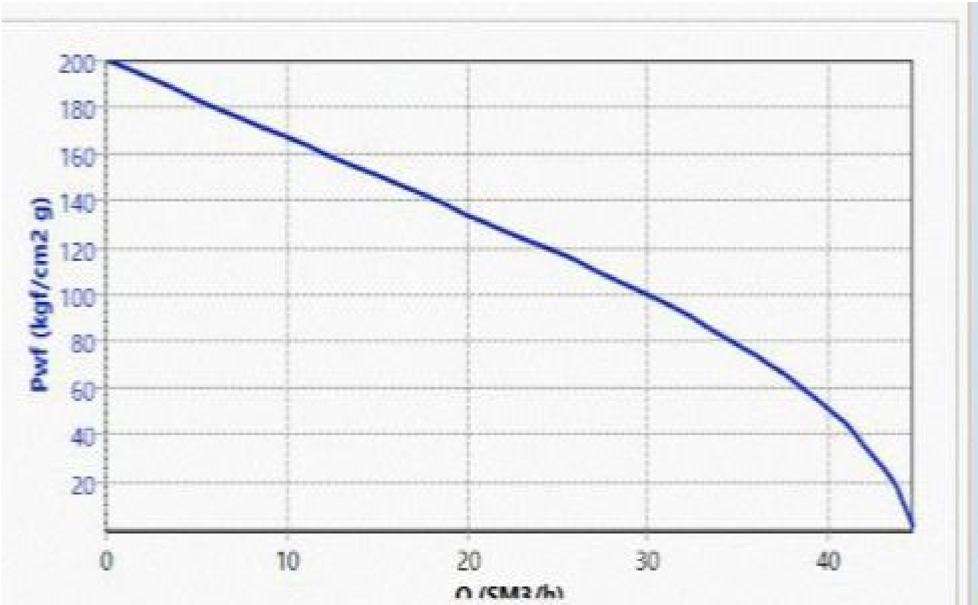

Figure 4.12: IPR Curve Of Well ONM112.

The figure above is a representation of Inflow performance curve demonstrates the absolute open flow (AOF) which is the maximum that our well can produce without restrictions (Maximum flow rate corresponding to zero dynamic pressure).

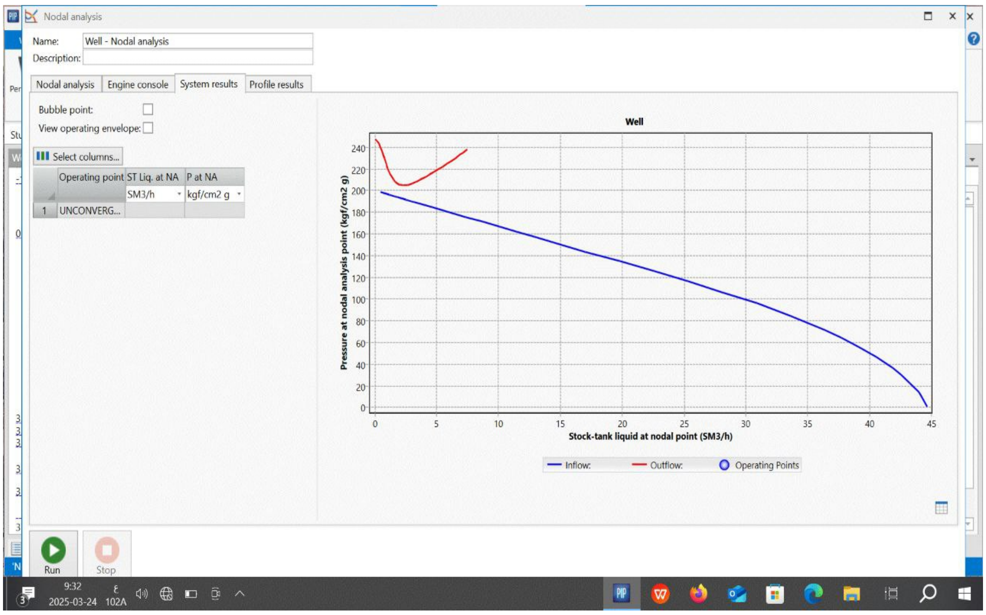

Figure 4.13: Well curve before optimization

The well is non-productive due to its inability to generate sufficient fluid flow. Preoptimization nodal analysis indicates that the operating point is non-convergent. Specifically, there is no intersection between the Outflow and Inflow performance curves. The Outflow curve, which represents the minimum pressure required to lift the fluid from the bottom-hole to the surface, exceeds the reservoir pressure. Consequently, the reservoir lacks the necessary energy to maintain the minimum pressure required for fluid elevation within the well. This results in backpressure against the reservoir, making it feasible to produce fluid to the atmosphere but not to the facilities due to existing constraints.

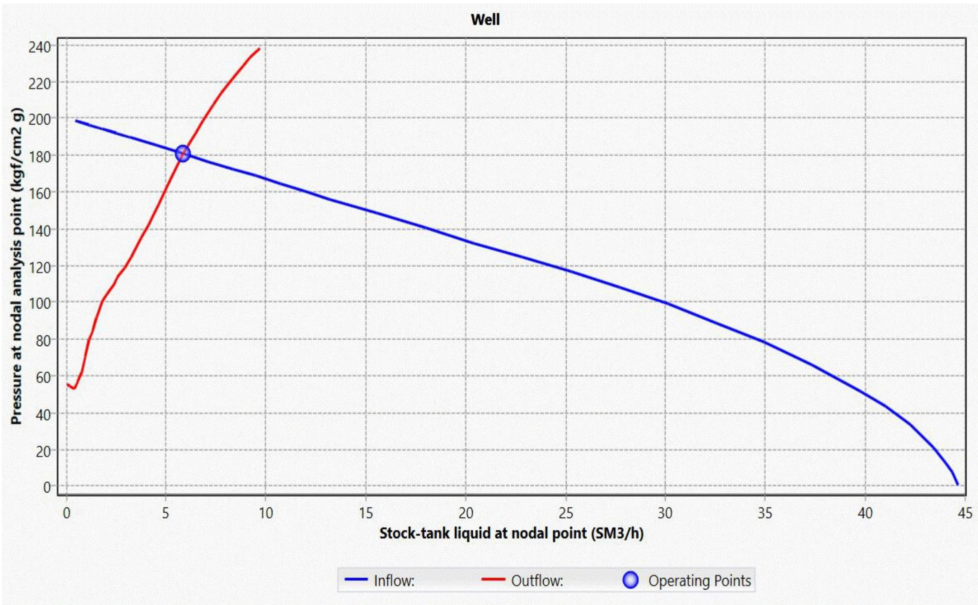

Figure 4.14: Nodal Well Analysis.

4.6 Gas-lift performance of ONM112 well:

In our study, the completion consists of a $4\frac{1}{2}$-inch production tubing (current state). The oil flows through the tubing. Based on the previous results, we can plot the gas-lift performance curve for well ONM112.

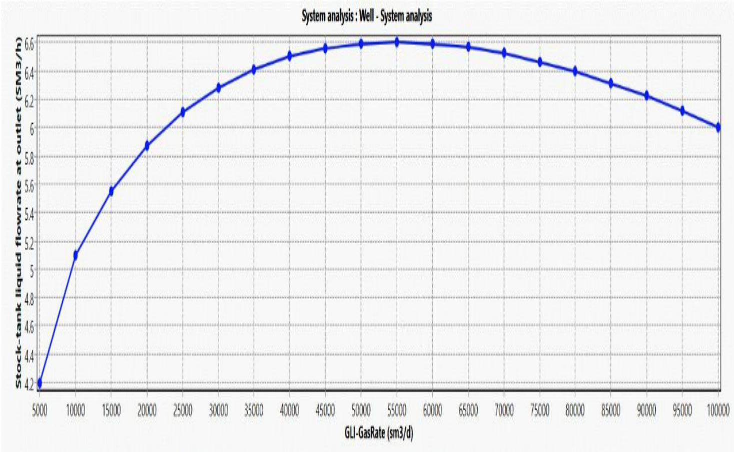

Figure 4.15: Gas-lift performance curve.

From this curve, we can see that the optimum gas injection rate is 20000sm3/d, which corresponds to an oil flow rate of 5.87m3/h. if this injection flow rate is exceeded, a drop in production will occur. This will lead to an annular flow regime which is ought to be avoided at all costs.

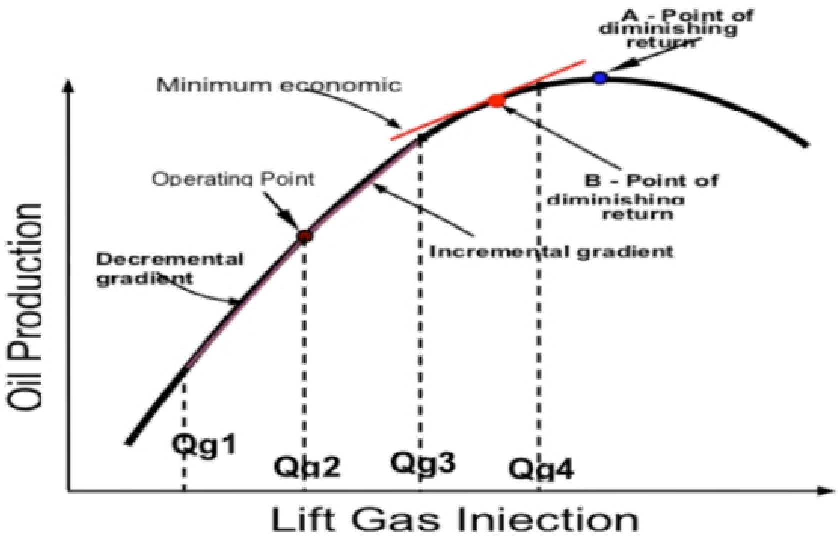

Figure 4.16: Injection rate optimization

[1]

	Case	CHP	Qgi	Ql	DIP
		kgf/cm2 g	sm3/d	SM3/h	m
1	CHP=139.9...	139.9997	4999.991	4.195233	3244.674
2	CHP=139.99...	139.9997	10000.01	5.102512	3244.674
3	CHP=139.99...	139.9997	15000	5.549968	3244.674
4	CHP=139.99...	139.9997	19999.99	5.871276	3244.674
5	CHP=139.99...	139.9997	25000.01	6.10799	3244.674
6	CHP=139.99...	139.9997	30000	6.282926	3244.674
7	CHP=139.99...	139.9997	34999.91	6.410307	3244.674
8	CHP=139.99...	139.9997	40000.09	6.499696	3244.674
9	CHP=139.99...	139.9997	45000	6.557848	3244.674

Figure 4.17: Determining the optimum gas lift flow rate.

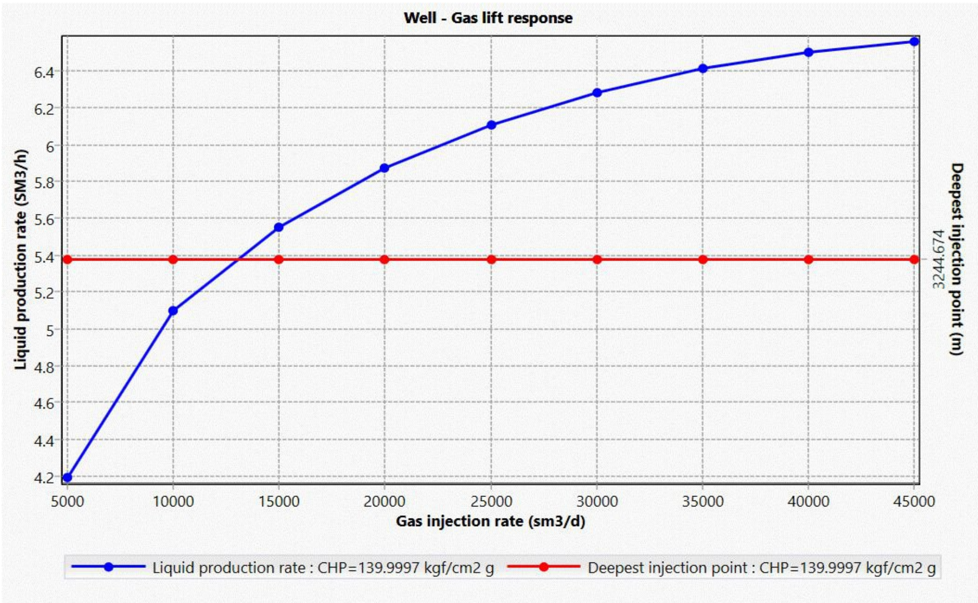

Figure 4.18: Liquid production in DIP

The noticeable increase in the liquid production rate from 4.2sm3/h to 6.4sm3/h at the deepest and optimum injection point(3244.67m) is a strong indication of enhanced performance due to the gas lift technique. This type of increase typically suggests that the injected gas at that depth has:

- Reduced the density of the fluid column in the well
- Consequently lowered the hydrostatic pressure
- Which helped fluids flow more efficiently from the reservoir

4.7 Comparison of oil flow before and after optimization

In the oil and gas field, the provided text pertains to a comparative analysis of oil flow rates pre and post-optimization, Specifically for Well ONM112. This table illustrates the comparison of oil flow rates before and after optimization for Well ONM112, along with the determined optimum flow rate.

WELL	**Q Oil (Sm3/d)**		**Q Gas**
	Before optimization	**After optimization**	**Optimum Sm3/d**
ONM112	0	140.88	20000

Table 4.3: Comparison of results before and after optimization.

The oil flow rate before optimization stood at 0 (Sm3/d), escalating significantly to 140.88 (Sm3/d) following optimization, the subsequent determination of the optimum flow rate post-optimization yielded 20000 (Sm3/d)

4.7.1 Results and discussion

This section focuses on the ONM112 well, located in a depleted reservoir with a current pressure of approximately 200 kg/cm^2. A gas lift injection rate of 20,000 Sm^3/d has been identified as critical to ensuring effective production. Accordingly, gas lift optimization is performed to determine the optimal oil production rate, utilizing the results obtained through PIPESIM simulation modeling.

4.8 Parameters influencing gas lift:

This section further explores the key parameters influencing gas lift operations. It is emphasized that the optimal performance of gas-lift-equipped wells is subject to variations in several parameters over time, which can often lead to operational disturbances and a decline in oil production.

Among the most sensitive and impactful parameters are:

- Tubing inter diameter.

- Choke diameter.

- Reservoir pressure.

4.8.1 Influence of the inside diameter of the tubing:

As part of this study, the internal diameter of the production tubing will be gradually varied, and the corresponding liquid flow rate will be recorded for each diameter. This approach aims to analyze and evaluate the impact of internal diameter variations on the well's production performance, with the goal of identifying the optimal configuration that ensures maximum production efficiency.

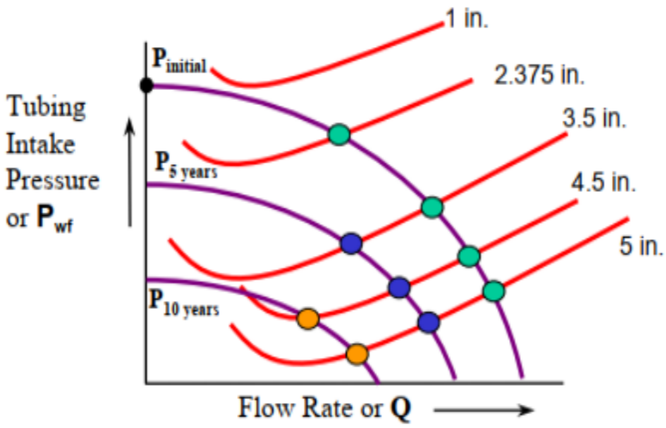

Figure 4.19: Tubing size selection vs. depleting reservoir pressures

- Tubing with too small a diameter can restrict production rates due to excessive frictional pressure losses.
- Overly large tubing, on the other hand, can cause the well to accumulate liquids and eventually cease flowing

We conduct tests using different tubing diameters and determine the corresponding oil flow rate for each case:

Inside diameter of tubing (inch)	Optimum Qo Sm3/d	Qg Sm3/d
2.441	87.72	20000
3.2	115.00	20000
3.92	140.88	20000

Table 4.4: Variation results for ONM112 tubing inside diameter.

From this table, we can see that increasing the inside diameter of the tubing means increasing the production area from the space available between the tubing and the casing, so the diameter that gives greater production is ID= 3.92 in

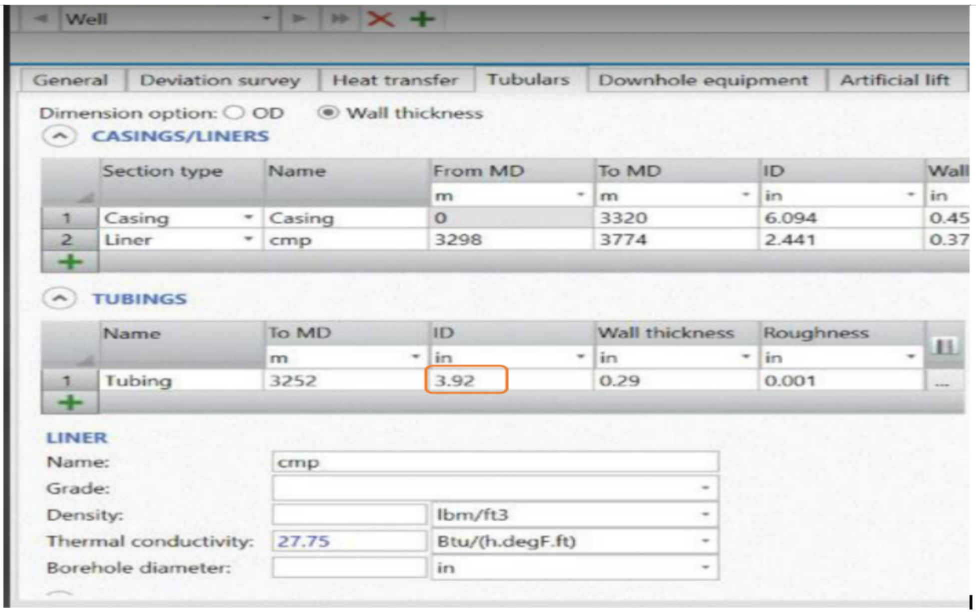

Figure 4.20: ID of tubing in PIPESIM SOFTWARE

4.8.2 Choke diameter influence:

The impact of choke diameter is under scrutiny to discern the diverse oil flow rates facilitated by varying diameters employed in gas-lift wells within Hassi Messaoud field. A pivotal consideration lies in selecting a choke size capable of maintaining an essential P (pressure differential) between the wellhead and the production line, thereby ensuring the establishment of a stable flow regime conducive to sustaining optimal long-term production parameters. The most suitable bean size for our case is 16 mm.

4.8.3 Gas injection parameters:

- Surface injection pressure : 140 kgf/cm2
- Surface injection temperature:27 degC
- Gas specific gravity: 0.732
- Maximum injection TVD: 3247.67m

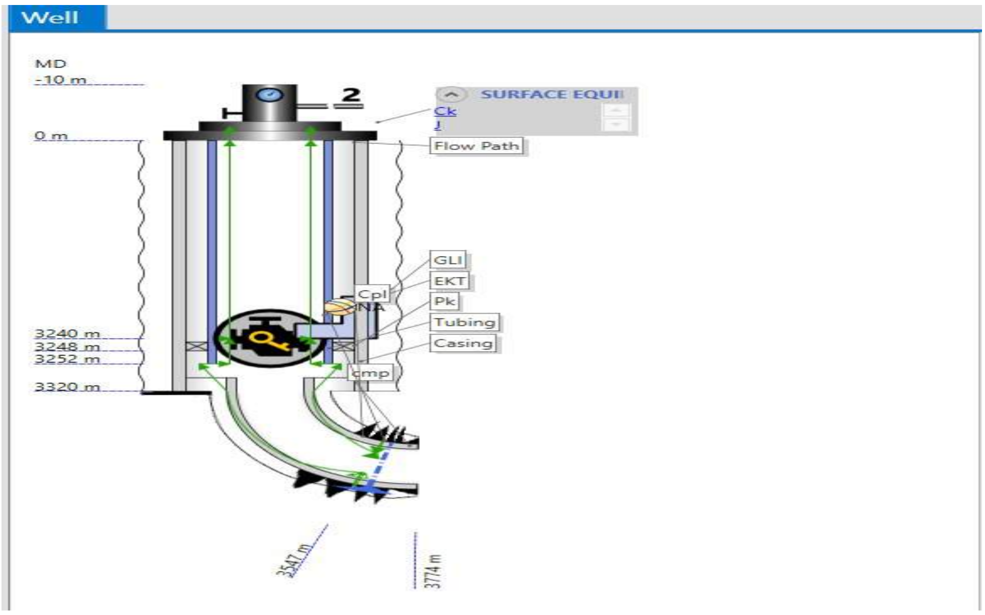

Figure 4.21: Gas lift injection depth.

4.8.4 Performance optimization on studied well:

Using data from the last Test, PVT, Completion and Gauging, we will optimize a single well. The data for this well are summarized in the following tables:

DATA	**ONM112**
Reservoir Pressure (kg/cm^2)	200
Oil API	45
Gas Specific Gravity	0.73
Water Gravity	1.02
GOR (Sm^3/Sm^3)	128
Tubing	4"1/2
MD (m)	3774

Table 4.5: Reservoir and Fluid Data

General Conclusion

The main objective of this study is to optimize the performance of non-flowing wells through gas injection, by evaluating the impact of reservoir depletion in the Hassi Messaoud field. The study specifically considers the gas lift system used to activate fluid flow from the reservoir to the surface, aiming to determine the optimal well parameters (oil and gas flow rates).

Gas lift is the most commonly used artificial lift method in the Hassi Messaoud (HMD) field. This technique involves injecting gas at the bottom of the production tubing to reduce the fluid density, thereby facilitating flow.

In this study, we analyzed several key parameters that influence the optimization of gas lift performance. The PIPESIM software were employed to improve the productivity of the ONM112 well. The parameters investigated include the volume of injected gas, injection depth, and the inner diameter of the production tubing. The following conclusions can be highlighted:

- The performance of the ONM112 well is enhanced by a significant gain in oil flow and a permanent production regime with optimum gas lift flow.
- Optimizing the gas injection rate minimizes the total pressure losses .
- For ONM112: The optimal gas rate (Qg) is 20000 sm^3/d, corresponding to an oil rate (Qoil) of 140.88 sm^3/d, compared to the initial oil rate (Qoil) of 0 sm^3/d, the optimal depth for the ID= 3.92 tubing is 3244.67m, and choke diameter=16mm. and OD CCE diameter = 1.66 inches

Recommendation :

Invest in high-precision sensors and reliable data logging equipment to guarantee the accuracy and consistency of input data used in nodal analysis. Regular calibration and maintenance of these instruments are essential, apply a suitable gas injection strategy aimed at maintaining reservoir pressure, thereby limiting pressure decline and sustaining long-term productivity.

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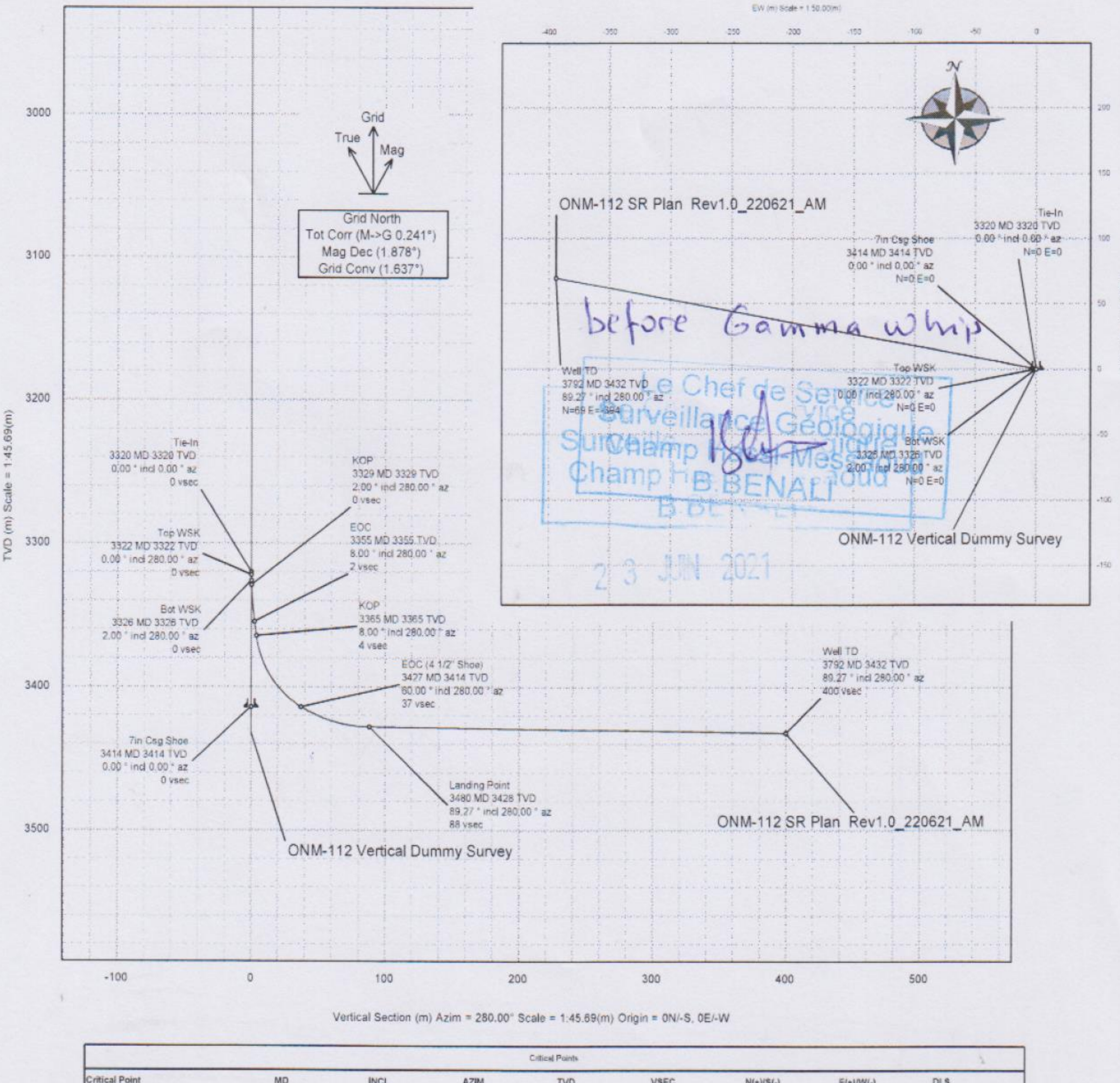
ANNEX

Schlumberger

SH-DP

Borehole:	Well:	Field:	Structure:
ONM-112 SR	ONM-112	Hassi Messaoud	ONM-112

Gravity & Magnetic Parameters	Surface Location Nord Sahara 1959 * INCT-Dza / UTM zone 31N	Miscellaneous
Model: HDGM 2021 Dip: 43.753° Date: 22-Jun-2021	Lat: N 31 43 1.26 Northing: 3513012.9m Grid Conv: 1.6369°	Slot: ONM-112 TVD Ref: Rotary Table(171.05m above MSL)
MagDec: 1.878° FS: 42061.409nT Gravity FS: 998.683mgn (9.80665 Based)	Lon: E 6 6 41.02 Easting: 794861.75m Scale Fact: 1.00067247	Plan: ONM-112 SR Plan Rev1.0_220621_AM

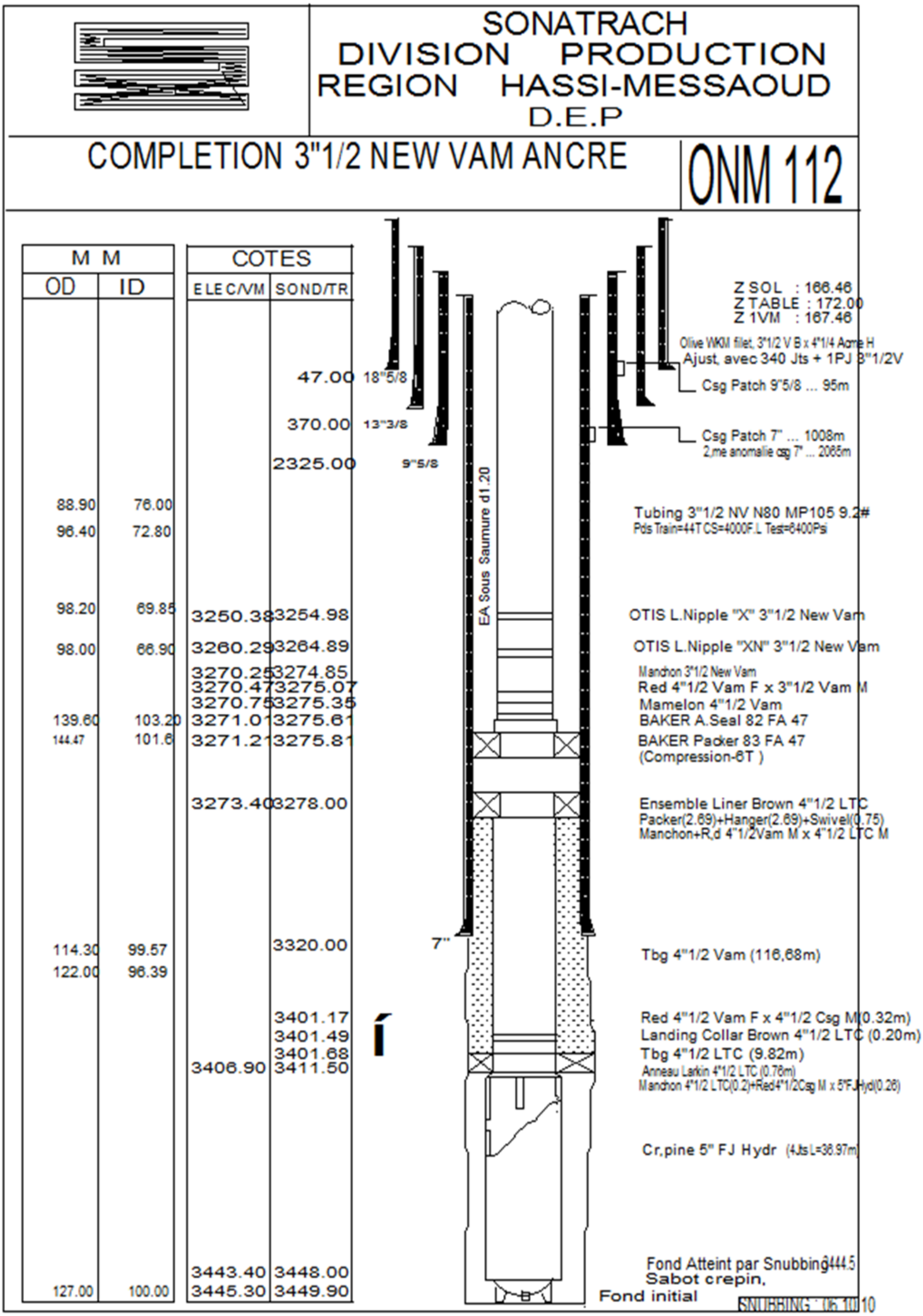


Vertical Section (m) Azim = 280.00° Scale = 1:45.69(m) Origin = 0N/-S, 0E/-W

Critical Points

Critical Point	MD	INCL	AZIM	TVD	VSEC	N(+)/S(-)	E(+)/W(-)	DLS
Marker MudLine	9.00	0.00	0.00	9.00	0.00	0.00	0.00	0.00
Tie-In	3320.00	0.00	0.00	3320.00	0.00	0.00	0.00	
Top WSK	3322.00	0.00	280.00	3322.00	0.00	0.00	0.00	0.00
Bot WSK	3326.00	2.00	280.00	3326.00	0.07	0.01	-0.07	15.00
KOP	3329.00	2.00	280.00	3329.00	0.17	0.03	-0.17	0.00
EOC	3354.71	8.00	280.00	3354.60	2.41	0.42	-2.38	7.00
KOP	3364.71	8.00	280.00	3364.50	3.81	0.66	-3.75	0.00
EOC (4 1/2" Shoe)	3426.52	60.00	280.00	3414.00	37.19	6.46	-36.63	25.24
Landing Point	3479.92	89.27	280.00	3428.00	88.13	15.30	-86.79	16.44
Well TD	3791.82	89.27	280.00	3432.00	400.00	69.46	-393.92	0.00

ONM112 Short Radius.



ONM112 Well Data Sheet.