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Presented By:

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-THEME-

Production optimization of HGAS3 well using gas-lift activation, a prospective application of nodal analysis approach

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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 HGAS3, which suffers from a production decline due to formation pressure dropping to 186 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 & PROSPER 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 8.1m³/h for HGAS3 well.

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

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

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 HGAS3, qui souffre d'une baisse de production due à la chute de la pression de formation à 186 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 et PROSPER,. 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 8,1m^3/h pour le puits HGAS3.

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 PROSPER, méthodes de levage artificiel, levage de gaz, champ de Hassi Messaoud, collection de données, complétion de puits, relation de performance de débit entrant, performance de levage vertical.

ملخص

في حقول النفط الناضجة مثل حقل حاسي مسعود، يستلزم انخفاض ضغوط المكامن استخدام طرق الرفع الاصطناعي للحفاظ على الإنتاج الاقتصادي، حيث يكون الرفع بالغاز هو السائد. يقلل الرفع بالغاز من ضغط التدفق في أسفل البئر عن طريق تقليل الضغط الهيدروستاتيكي للسوائل وتخفيف الانخفاض السريع لضغط المكمن. ومع ذلك، فإن محدودية سعة الغاز المتاحة وقدرة الضاغط تستلزم تحسينها لتحقيق أقصى قدر من الاسترداد. تركز هذه الدراسة على تحسين رفع الغاز للبئر HGAS3 الذي يعاني من انخفاض الإنتاج بسبب انخفاض ضغط التكوين إلى 186 بار وانخفاض نسبة الغاز إلى السائل (GLR).تتضمن منهجية البحث جمع بيانات شاملة، بما في ذلك تفاصيل إكمال البئر، وبيانات اختبار البئر، وتحليل نسبة الغاز إلى السائل. ثم يتم تطبيق مبادئ التحليل العقدي لتحسين الإجراءات التشغيلية من خلال تعديل تعبيرات التدفق الخارج. ويساعد هذا الإطار النظري على تحديد معاملات الأداء المثلى لتعظيم كفاءة الإنتاج. باستخدام برنامج PIPESIM & PROSPER، تُظهر النتائج تحسنًا كبيرًا، حيث تم تحقيق معدل حقن غاز أمثل يبلغ 20000 متر مكعب/يوم وزيادة في معدل إنتاج النفط بمقدار 8.1 متر مكعب/ساعة لبئر HGAS3.

وبالإضافة إلى ذلك، تقترح هذه الدراسة تغييرات في قطر الأنبوب، وإعدادات الخنق، ومعدل حقن رفع الغاز.

الكلمات المفتاحية: التحليل العقدي، الارتباط، التحسين، التدفق، التدفق الخارجي، التدفق الداخل، PIPESIM، برنامج PROSPER، طرق الرفع الاصطناعي، رفع الغاز، حقل حاسي مسعود، جمع البيانات، إكمال الآبار، علاقة أداء التدفق، أداء الرفع العمودي.

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Thank you

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.

TOBCHI MOHAMED

Dedication

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ABDI DJABER ABDALLAH

Summary

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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.

SARA: Chemical analysis in the laboratory.

KOP: Kick Off Point.

LPP: Pre-perforated liner.

LCP: Perforated Cemented Liner.

PFD: Dynamic bottom pressure.

PFS: Static bottom pressure.

ID: Interior diameter.

ED: exterior diameter.

CCE:Concentric.

RMS: Root Mean Squared.

API: density.

$\boldsymbol{Bo}$: Volumetric factor of the oil bottom (Rm3/STm3).

$\boldsymbol{Boi}$: Initial oil volume factor (Rm3/STm3).

$\boldsymbol{Bg}$: Gas background volumetric factor (Rm3/STm3).

$\boldsymbol{Bgi}$: Initial gas background volumetric factor (Rm3/STm3).

d: Density.

D: Tubing inside diameter (mm).

d: Concentric outside diameter (mm).

H: Height (m).

PI: Productivity index (bbl/d*psi).

$\boldsymbol{Pb}$: Bubble pressure (bar).

$\boldsymbol{Pg}$: Bearing pressure (bar).

PDF: Gas pressure to be injected (bar).

$\boldsymbol{Pr}$: Reservoir pressure (bar).

$\boldsymbol{Psep}$: Separation pressure (bar).

$\boldsymbol{Pwf}$: Dynamic bottomhole pressure (psi).

Q: Product flow rate (bbl/day).

$\boldsymbol{q0}$: Incoming flow (bbl/d).

$\boldsymbol{qmax}$: Maximum flow rate (bbl/d).

$\boldsymbol{Qg}$: Gas flow rate (m3/day).

$\boldsymbol{Rsi}$: Initial dissolution GOR ($m3/m3$).

$\boldsymbol{Rs}$: dissolution GOR ($m3/m3$).

$\Delta\boldsymbol{p}$: Differential pressure (bar).

Equations list

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General Introduction

Gas lift serves as a pivotal artificial lift method employed primarily to enhance oil production rates from low-pressure reservoirs **[9]**. This technique involves injecting pressurized gas continuously into the bottom hole of a well to bolster reservoir energy. The injected gas facilitates the movement of fluids to the surface through several mechanisms, including reducing fluid load pressure due to decreased density, gas expansion, and displacement **[10, 11]**.

Gas lift is favored among artificial lift methods, especially when readily available gas for injection is accessible. It offers cost-effectiveness compared to rod pumps, ease of deployment, operational flexibility across varying conditions, minimal maintenance requirements, and the potential for maximizing liquid production **[12]**.

The objective of gas lift is to elevate fluids to the wellhead while maintaining low bottomhole pressure, ensuring a significant pressure differential between the reservoir and the bottom hole. Decreasing bottom hole pressure through gas injection typically boosts fluid production rates by reducing the density of the fluid column, thereby enabling larger volumes of fluid to flow through the tubing **[13,14]**. However, excessive gas injection can elevate bottom hole pressure, diminishing oil production rates due to gas slippage, where gas moves faster than liquid, leaving behind a reduced liquid flow **[13, 14]**.

Therefore, achieving optimal gas injection rates and points is crucial for maximizing oil production, often depicted through continuous gas lift performance curves **[13, 14]**.

Successful gas lift designs, such as those detailed in **[15]**, involve modifying tubing diameter, choke settings, and gas lift injection rate to optimize available pressure and gas requirements, Designing effective gas lift systems requires accurate estimation of pressure drops in multiphase flow within oil wells, a complex task that significantly influences gas lift design and calculations. Previous studies evaluated popular pressure drop correlations—Hagedorn and Brown, Duns and Ros, and Orkiazewski—against multiphase flow data from numerous wells **[16]**. Among these, the OLGAS v. 6.2.7 3-Phase correlation demonstrated superior accuracy, especially in handling three-phase flow conditions, and thus, will be similarly evaluated for applicability in the present study, ensuring robust and optimized gas lift design and operation.

Nodal analysis is one of the methods used to study well performance. . It can be used to analyze production problems and improve productivity.

In this study, we will show the interest of nodal analysis to model the production system and predict possible scenarios for improving and optimizing production. By applying this method to HGAS3 well on the Hassi Messeaud field, we studied the profitability of gas lift activation

Resulting:

The optimal gas rate (Qg) is 20000 sm^3/d, corresponding to an oil rate (Qoil) of 194.64 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 10318 feet, and choke diameter=20 mm.

To this end, this study is organized as follows:

- The first chapter is devoted to general information on well activation.
- The second chapter presents general information on production system analysis.
- The last chapter is a study of HGAS3 well.

This study is carried out with the help of two software packages: PIPSIM (to determine optimum gas injection rate and maximum oil flow rate) and PROSPER (for determining casing pressure and injection depth).

Well Activation

Chapter I Well Activation

I.1 Introduction:

As the reservoir's production began to deplete, therefore at one point become insufficient to ensure normal production. The only way to keep production at a high level is to use secondary and sometimes tertiary recovery. But there are other ways to extract oil; these methods are called enhanced or artificial recovery. **[17]**

I.2 Activation mode:

Well activation allows the production of non-eruptive wells, mainly related to oil wells. Activation may be necessary from the start of exploitation when the reservoir does not have sufficient energy to bring the fluid up from the bottom to the processing facilities or when the productivity index of the well is considered insufficient.
To activate non-eruptive wells and put them into production, you can act according to one of the following parameters:

→Reducing the height “H” involves putting the well in pumping mode.

→Reducing the density “D” consists of injecting a less dense liquid, which can be a gas, and this process is called; Gas lift. **[17]**

I.3 Activation types:

I.3.1 Pump:

A pump placed below the dynamic fluid level of the well raises the crude oil to the surface, a mechanical process typically used in shallow wells. There are several types of pumps, the most common modes in the world are:

- Rod pumps.
- Centrifugal pumps.
- Hydraulic pumps.
- PCP (progressive cavity) pumps. **[17]**

I.4 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 **[17]** (**Fig I-1**).

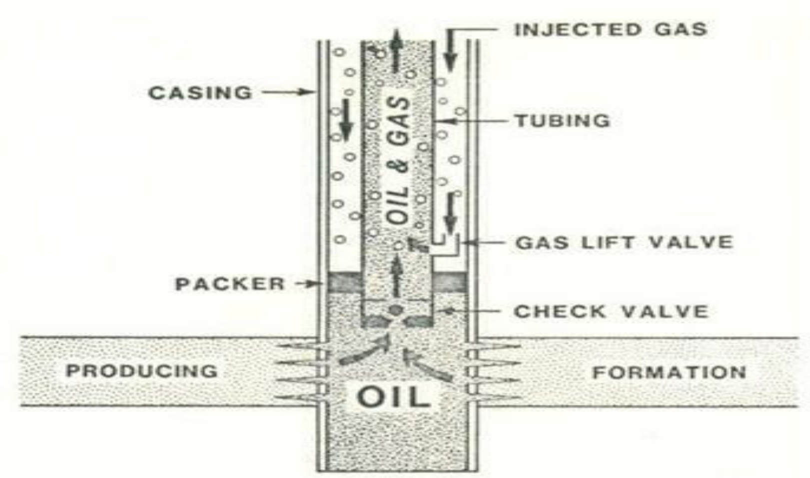


Figure I-1: Gas lift system. [17]

I.4.1 Gas-lift principle:

The principle of gas lift consists of injecting gas as deep as possible to lighten the column of fluid contained in the tubing. This is similar to adding power downhole to help the tank produce the effluent it contains all the way to the separator **[17]** (**Fig I-2**).

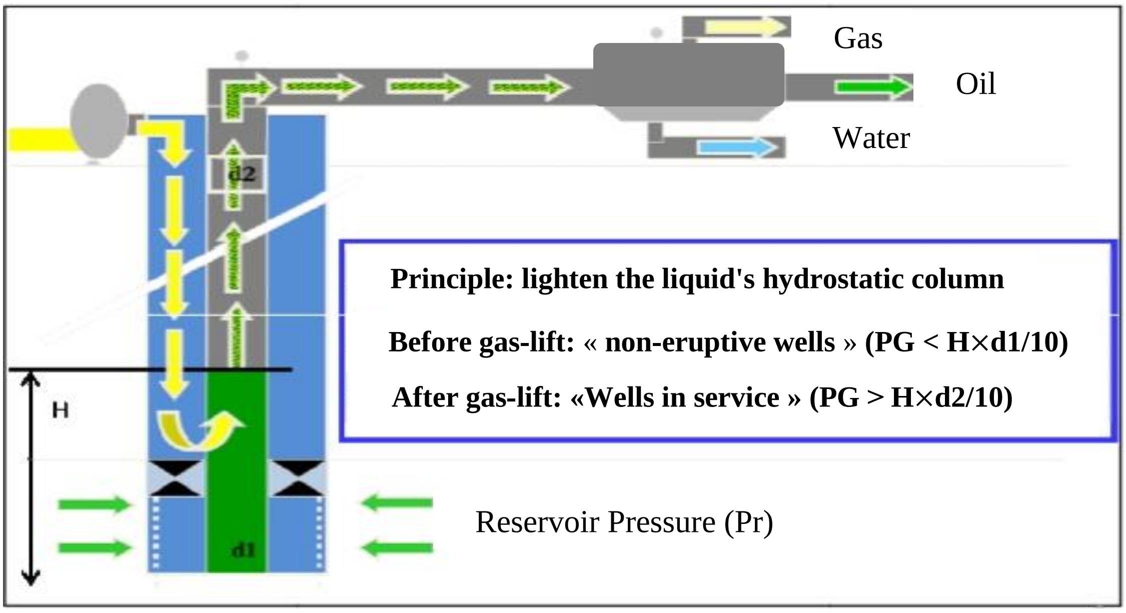


Figure I-2: Gas lift principle. [17]

The quantity of gas to be injected must not exceed a limit, beyond which its efficiency decreases. This is known as the optimum GLRt (GLRt = total Gas Liquid Ratio). The GLRt is the ratio between the volume of gas (injected + produced) and the liquid produced when the well's production reaches its maximum. **[17]**

I.4.2 Gas-lift types:

I.4.2.1 Classification according to injection mode:

- **Continuous gas-lift:**

This is a method that enhances the natural process of oil production by associated gas (free or dissolved in the reservoir) through gas injection into the tubing or annulus. The injection point and injection flow rate are determined to alleviate the load. The effluent column must be wide enough to achieve a sufficient bottomhole pressure according to the desired flow rate. Continuous gas lift can be adapted to a wide range of production conditions in gas wells, including high angle wells, wells with high gas-oil ratio, and wells with sand, wax, or scale. However, it is not suitable for heavy oil or emulsion wells. **[17]** (**Fig I-3**)

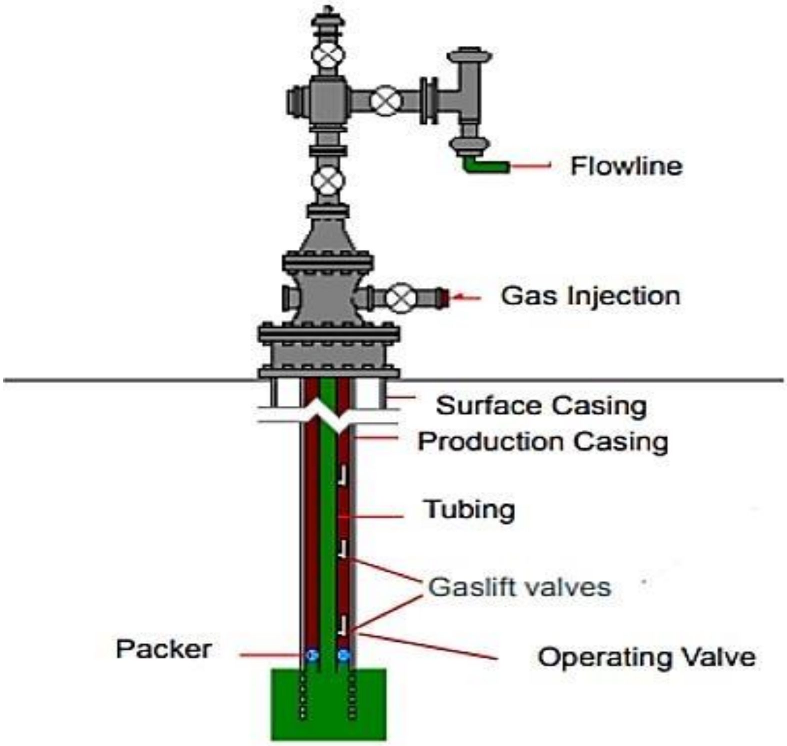


Figure I-3: continuous gas lift system.

- **Intermittent gas-lift:**

It consists of injecting, intermittently, high flow rates of a predetermined volume of pressurized gas into the lower part of the production column with the aim of displacing the liquid volume above the injection point upwards **[17]** (**FigI-4**).

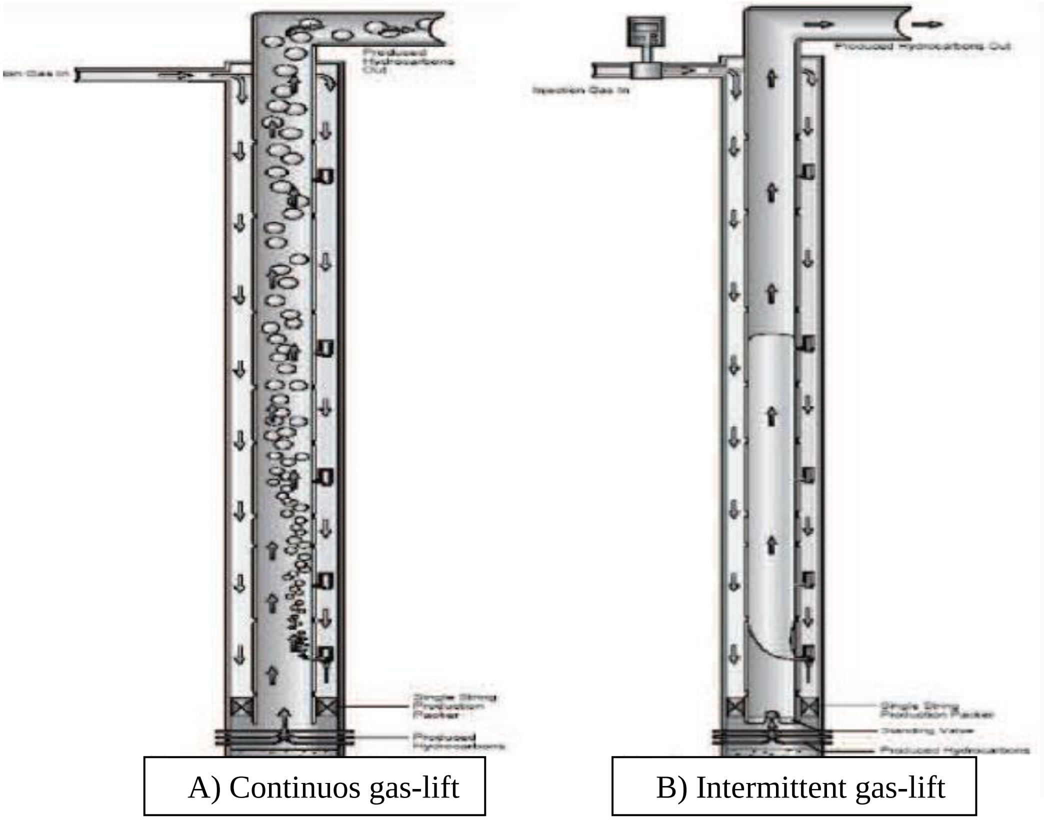


Figure I-4: Continuos/intermittent gas-lift Injection. [17]

I.5 Various gas lift casings:

Gas lift can be used for both single and multiple completions, and well production can be direct or reversed. **[17]**

I.5.1 Completion for direct gas-lift:

The gas injection is carried out in the annulus space between the tubing and casing, while production occurs through the tubing. This design is the most common due to its simplicity and operational ease **[17]** (**Fig I.5**).

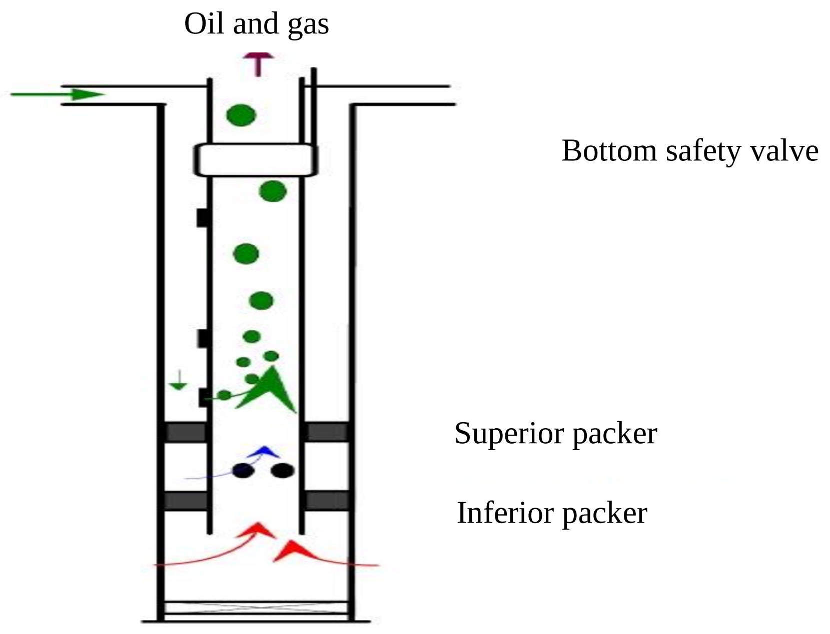


Figure I-5: Direct gas-lift completion. [17]

I.5.2 Completion for reversed gas-lift:

I.5.2.1 Concentric tubing string:

The gas is injected into a small concentric tube known as "macaroni." This type of configuration is very common. The system operates similarly with larger diameter concentric tubes deployed over the well's lifespan **[17]** (**Fig I.6**).

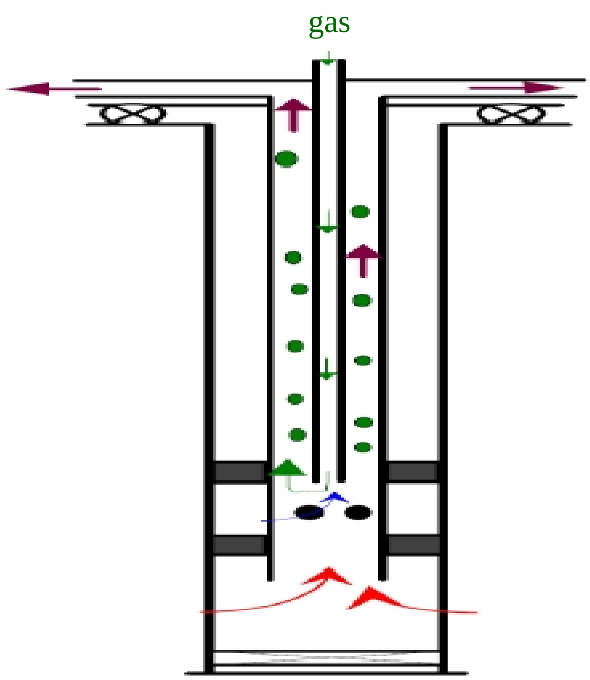


Figure I-6: Concentric tubing completion. [17]

I.5.2.2 Gas lift with production in casing:

For extremely high flow rates, it is feasible to design wells where the reservoir production flows directly into the casing, with gas injection into the tubing (**Fig. I.7**).This method has several drawbacks:

- It is impossible to take measurements on the effluent side, i.e., between the tubing and the casing, such as pressure or temperature measurements, which are necessary for large volumes of gas.
- The design and equipment are specialized.
- The well is poorly suited for intermittent gas lift. **[17]**

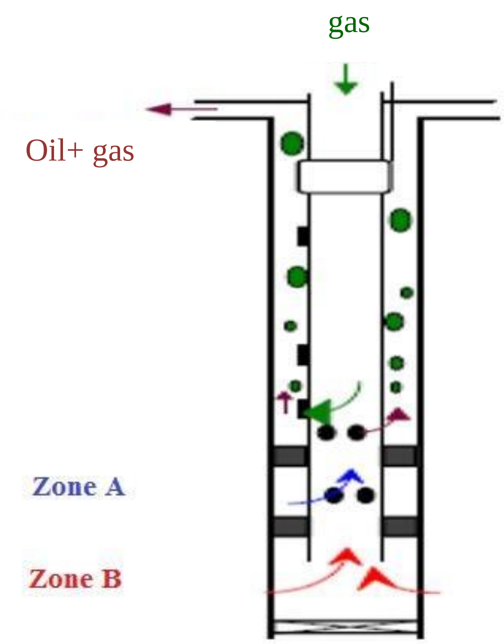


Figure I-7: Production in the casing. [17]

I.6 Side pocket mandrel (SPM):

A side pocket mandrel is a specialized component used in oil and gas wells, designed to hold and facilitate the insertion and retrieval of various types of downhole tools and equipment, such as gas lift valves or chemical injection valves, without requiring a full workover of the well. The mandrel is installed as part of the tubing string and features a side pocket that is offset from the main bore of the tubing. This side pocket allows tools to be placed in the mandrel through the use of wireline or coiled tubing operations, enabling the maintenance or adjustment of downhole equipment while maintaining the production flow through the main bore. This flexibility makes side pocket mandrels essential for optimizing well performance and ensuring efficient production operations.

The key subsurface components of a gas lift system are the gas lift valves that regulate the flow of injected gas into the producing fluid column. These pressure-operated devices—usually 1 or 1.5 inches in diameter and about 16 to 24 inches long—are placed in mandrels that are set at selected depths in the tubing string, most often in a conventional or side pocket configuration. (**FigI-8**)

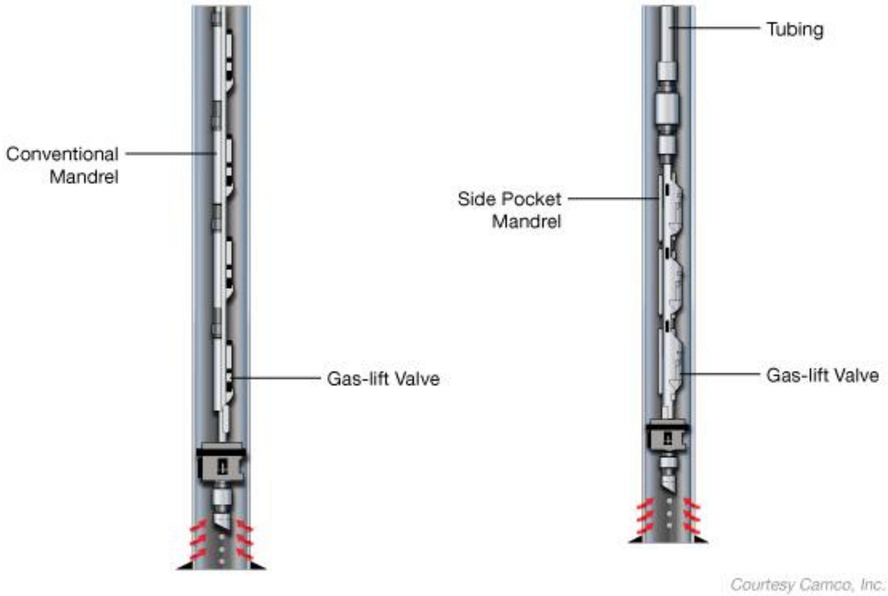


Figure I-8: Conventional and side pocket mandrel installations.

I.7 Factors to consider in gas lift design:

I.7.1.1 Gas pressure to be injected:

The bottom injection pressure is the pressure at which the gas reaches the injection point (**Fig I-9**). It is chosen in such a way as to prevent the adsorption of the effluent by the formation, and it is given by the following law**[17]**:

- For a direct system (tubular production, i.e., injection through the tubing annular space - concentric, and production through the concentric) :

$$P_{DF} = H\frac{D^2}{d^2} \times \frac{\gamma}{10} \quad (Bar)$$

P_{DF}: Gas pressure to be injected

H: Static height measured from the injection point in [m].

D: Inside diameter of tubing in [mm].

d: Outside diameter of concentric in [mm].

γ: Oil density.

- For an indirect system (annular production, i.e., injection through the concentric and production through the annular space) **[17]**:

$$P_{DF} = H \frac{D^2}{D^2 - d^2} \times \frac{\gamma}{10} \ (Bar)$$

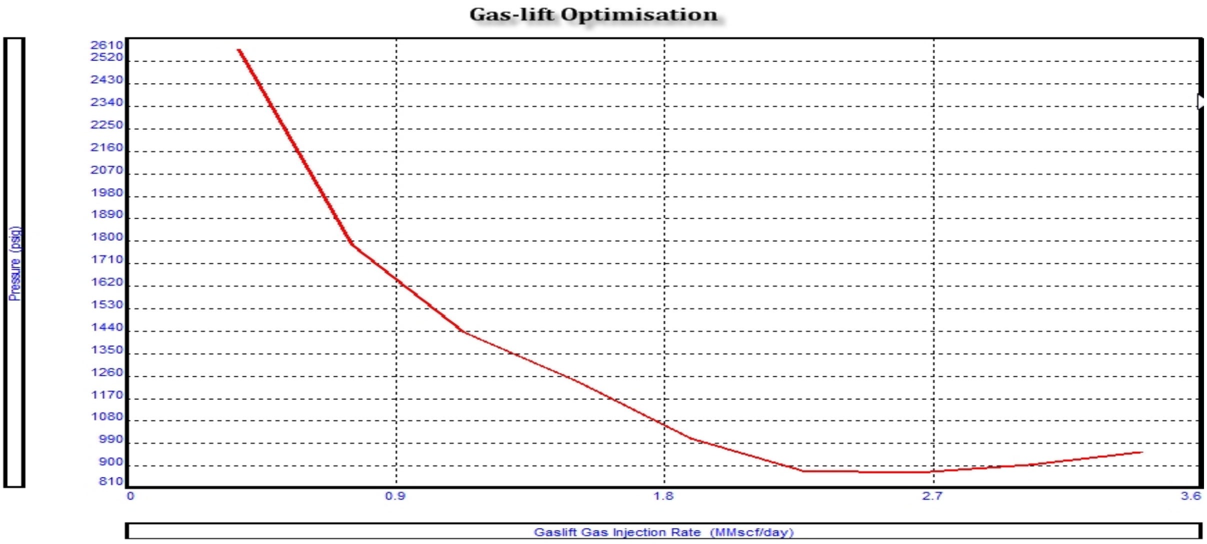


Figure I-9: Impact of gas-lift injection rate on downhole pressure. [17]

I.7.1.2 Gas injection depth:

The deeper the injection point, the more effective the injected gas is. A deep injection point brings a very clear improvement in well production, especially for high PI. Some completions are equipped with a packer with a bypass to allow the gas to descend as close as possible to the reservoir. **[17]**

I.7.1.3 High PI and Skin effect:

The production of a well directly depends on the drawdown applied to the formation and thus on the bottomhole flowing pressure. Gas-lift activation reduces this pressure like all activation methods do. The effect is striking in high PI wells where gas-lift enables spectacular flow rates that other activation methods cannot achieve.

The skin effect refers to damage in the first few centimeters of the reservoir. The skin effect directly reduces well production and must be addressed through various known methods such as acidizing, perforation, etc. A well with reduced IP requires a larger quantity of gas. **[17]**

I.8 Pressure drop:

The key point of a gas lift design is pressure losses in multiphase flow. These pressure losses are the sum of two factors:

- Effluent friction losses on the tubing.
- The hydrostatic weight of the effluent (gas, water and oil) in the tubing (gravity).

Gas-lift is used to increase well production by injecting gas into the tubing at the deepest possible point to reduce pressure losses (**FigI-10**).

This will have two opposite effects:

- Increased friction losses (negative effect).
- Reduced column weight (positive effect).

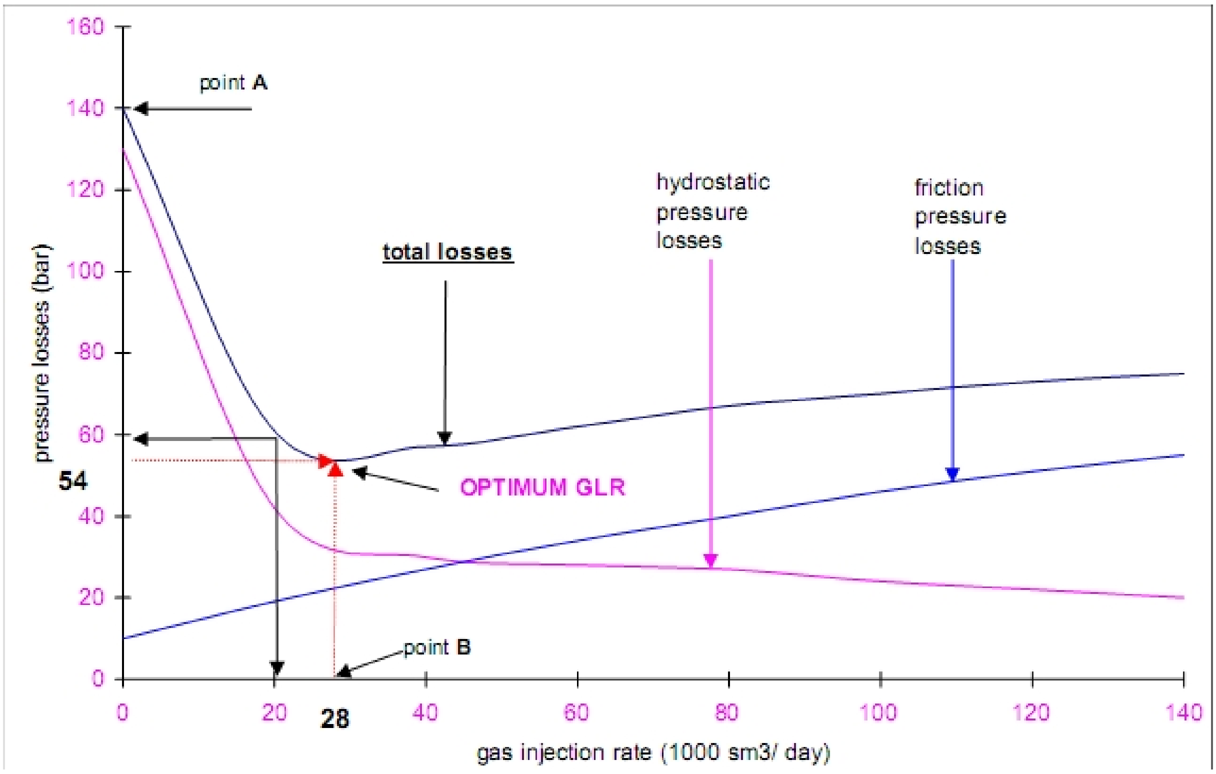


Figure I-10: Pressure losses evolution according to gas injection rate.

The figure above shows the evolution of pressure losses as a function of GLR, where two different zones can be seen:

In the first zone, increasing GLR reduces total and gravitational pressure drop, despite increasing frictional pressure drop.

In the second zone, the total pressure drop increases, with the increase in gravitational and frictional pressure drops, despite the increase in GLR.

The minimum total pressure drop corresponds to an optimum GLR.

Injecting large volumes of gas is a problem for lines and surface installations. This gas has to be transported to the station and has to be separated, so it adds pressure losses in the pipelines that can disturb producers.

The quantity of gas to be injected must be carefully determined to achieve optimum production. **[17]**

I.9 Advantages and disadvantages of Gas-Lift:

- The availability of gas and the costs for compression and injection are major considerations in planning a gas lift installation. Where these gas injection requirements can be satisfied, gas lift offers a flexible means of optimizing production.
- It can be used in deviated or crooked wellbores, and in high-temperature environments that might adversely affect other lift methods, and it is conducive to maximizing lift efficiency in high-GOR wells.
- Wireline-retrievable gas lift valves can be pulled and reinstalled without pulling the tubing, making it relatively easy and economical to modify the design.
- On the negative side, additional costs for gas processing and surface compression can adversely affect profitability.
- Corrosion and paraffin formation tend to increase system pressure losses and reduce lift efficiency.
- System efficiency is also sensitive to tubing diameter and surface flowline length.
- Another disadvantage of gas lift is its inherently higher bottomhole pressure compared with pump-assisted lift systems. This makes it difficult to fully deplete low-pressure, low-productivity wells.

Production System Analysis

Chapter II Production System Analysis

II.1 Introduction:

The primary function of any production well is to facilitate the transportation of oil or gas from its original location in the reservoir to the stock tank or sales line. This process necessitates energy to counteract frictional losses within the system and to elevate the products to the surface. The fluids must traverse through the reservoir and the piping system, eventually flowing into a separator for gas-liquid separation. The production system can range from being relatively simple to comprising numerous components where energy or pressure losses occur. For instance, **Figure II-1** illustrates a complex production system, highlighting several components where pressure losses occur.

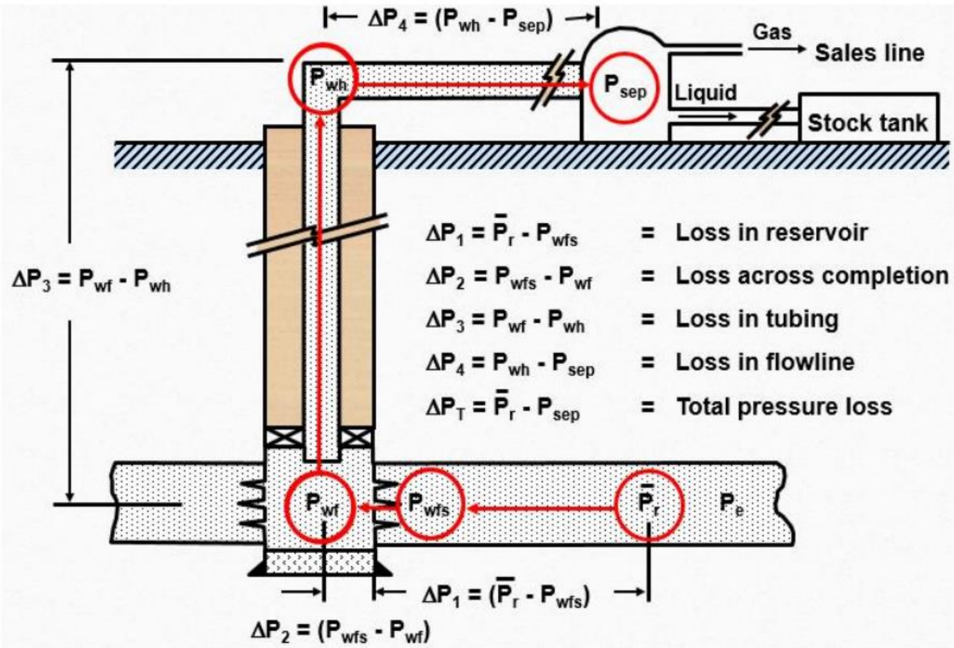


Figure II-1: System description and pressure losses. [4]

The pressure drop in the total system at any given time is the difference between the initial fluid pressure and the final fluid pressure, i.e., PR - Psep. This pressure drop is the cumulative sum of the pressure drops occurring in all the components of the system. Since the pressure drop through any component varies with the producing rate, the producing rate is controlled by the selected components. The selection and sizing of individual components are crucial, but due to the interaction among the components, a change in the pressure drop in one may alter the pressure drop behavior in all the others. This happens because the flowing fluid is compressible. Therefore, the pressure drop in a particular component depends not only on the flow rate through the component but also on the average pressure that exists in the component. The final design of a production system cannot be separated into reservoir performance and piping system performance and handled independently. The volume of oil and gas flowing into the well from the reservoir depends on the pressure drop in the piping system, and the pressure drop in the piping system depends on the volume of fluid flowing through it. Therefore, the entire production system must be analyzed as a unit.

The production rate or deliverability of a well can often be severely restricted by the performance of only one component in the system. If the effect of each component on the total system performance can be isolated, the system performance can be optimized in the most economical way. Past experience has shown that large amounts of money have been wasted on stimulating the formation when the well's producing capacity was actually being restricted because the tubing or flowline was too small. Another example of errors in completion design is to install tubing that is too large. This often happens on wells that are expected to produce at high rates. It will be shown that this practice not only wastes money on oversized equipment, but tubing that is too large can actually reduce the rate at which a well will flow. This can cause the well to load up with liquids and die, which necessitates the early installation of artificial lift equipment.

A method for analyzing a well, which will allow determination of the producing capacity for any combination of components, is described in the following section. This method may be used to determine locations of excessive flow resistance or pressure drop in any part of the system. The effect of changing any component on the total well performance can be easily determined. **[4]**

II.2 Nodal analysis:

Nodal Analysis is employed to evaluate a complete production system (starting with the static reservoir pressure and ending with the separator) and predict the throughput. It is an optimization technique that can be used to analyze production problems and improve well performance. It is used extensively in oil and gas fields since it was introduced by Gilbert in the 1950s. It is based on combining the reservoir's ability to produce fluids towards the bottom of the well with the tubing's ability to produce fluids towards the top of the well.

The practical use of Gilbert’s ideas was limited due to the restrictions of the methods available at the time to model the performance of individual elements of the system. Later the choice was wide with the computational models available and the advent of which led to a resurgence of Gilbert’s ideas in the 1980s. The new contribution aimed at numerical simulation of the production system makes it possible to optimize production. **[1]**

II.2.1 Applications of nodal analysis:

The nodal system analysis approach may be used to analyze many producing oil and gas well problems. The procedure can be applied to both flowing and artificial lift wells. If the effect of the artificial lift method on the pressure can be expressed as a function of flow rate. The procedure can also be applied to the analysis of injection well performance by appropriate modification of the inflow and outflow expressions. **[2]**

A partial list of possible applications is given as follows:

- Selecting tubing size and flowline size.
- Gravel pack design and Surface choke sizing.
- Subsurface safety-valve sizing,
- Analyzing an existing system for abnormal flow restrictions.
- Artificial lift design and well stimulation evaluation.
- Analyzing effects of perforating density.
- Determining the effect of compression on gas well performance.
- Predicting the effect of depletion on producing capacity.
- Allocating injection gas among gas lift wells.
- Prediction of the effect of depletion on production.
- Analyzing a multi-well producing system
- Relating field performance to time

Nodal analysis is often used to optimize the following parameters:

- Wellhead or separator pressure, Completion effect, Well skin.
- Choice of manifold dimensions and optimization of the manifold network, Optimization of gas lift production. **[4]**

II.2.2 Procedures for implementing Nodal Analysis:

Nodal Analysis is applied to analyze the performance of systems that are made up of components that interact with each other. The general procedure for solving most cases involves the following steps:

- Determining which components of the system are the most sensitive.
- Select the components to be optimized.
- Obtain the data needed to calculate IPR (Inflow Performance Relationship).

Determine the effect of changing the characteristics of the selected components (diameter for example) by plotting inflow as a function of flow rate.

- Determine a specific objective for the case under study.
- Select the location of the node that will be affected by the change in the component.
- Choose the appropriate correlation and adjust this correlation using the correction factor L.
- Develop the expressions for inflow and outflow.
- By clicking on the ‘Sensitivities’ box, you can input different values for the parameter, resulting in different performance curves and hence different operating points.
- The optimal oil flow is the one that maximizes this curve. **[4]**

II.2.3 Production system losses from the reservoir to the separator:

Nodal systems analysis approach is an adaptable methodology that can enhance the performance of numerous well systems. To implement this systems analysis procedure on a well, it is crucial to calculate the pressure drop that will transpire in all the system components. These pressure drops are dependent not only on the flow rate but also on the size and other characteristics of the components. Without precise methods to calculate these pressure drops, the systems analysis could yield incorrect results.

The subsequent sections of this text introduce the most recent and accurate methods for determining the relationship between flow rate and pressure drop for all components. This necessitates a comprehensive review of reservoir engineering concepts to ascertain reservoir inflow performance, an understanding of multiphase flow in pipes to calculate tubing and flowline performance, procedures to determine the performance of perforated completions, gravel-pack completions, and damaged or stimulated wells, and an understanding of artificial lift systems.

Once procedures are presented to analyze each component separately, the systems analysis approach will be applied to various wells to demonstrate the procedures to optimize well performance. **[2]** (**Figure II-2**)

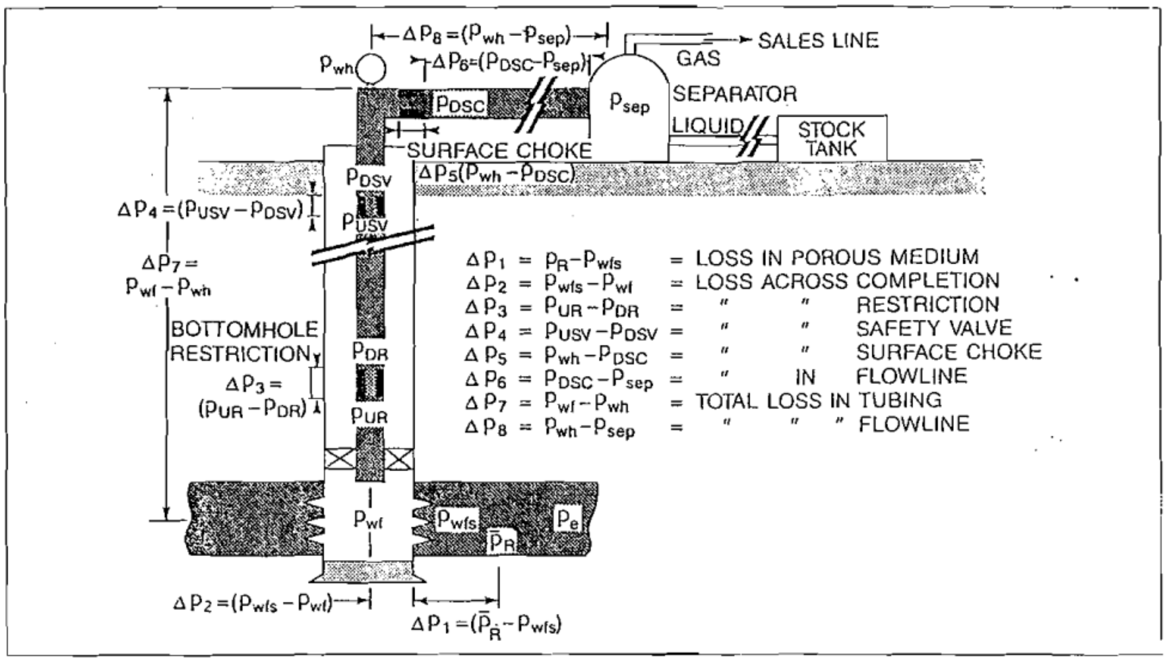


Figure II-2: Possible pressure losses in complete system. [2]

Figure II-2 shows various pressure drops that can occur in the entire production system from the reservoir to the separator.

II.3 Well performance:

Well performance can be defined simply as the ability of a well to produce reservoir fluids at the surface either by natural flow or by artificial lift. The reservoir pressure controls the flow through the production system, and the surface separation pressure is designed to optimize production and retain the lighter hydrocarbon components in the liquid phase, this pressure is maintained by mechanical devices, such as pressure regulators. The fluid flows from reservoir into well and the latter is connected to surface facilities such as a pipeline, manifold, and separator, etc. All these elements together are called oil or gas production system.

In an oil or gas production system the flow of fluids from the reservoir to the separator at the surface can be subdivided as follows:

- Flow in the porous medium.
- Flow in vertical or directed tubing.
- Flow through a horizontal or inclined pipe at the surface.

During production, several types of pressure drop slow down the flow of fluid from the reservoir to the surface, thereby reducing production and contributing in pressure drop. **[1]**

II.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.

The choice of node location depends on the purpose of the study. They can be the following locations:

1. Separator: the choice of the node at the separator makes it possible to study the effect of separation pressure on well operation.
2. Choke: this location allows us to study the effect of the choke, and to control the flow of production rate.
3. Well head: the choice of the node at the well head enables us to study the effect of wellhead diameter on well performance.
4. Bottom of the well: the choice of the node at the bottom of the well allows us to study the effect of IPR and tubing diameter on well performance.
5. At the perforations: the choice of the node at the perforations allows us to study the effect of perforation density in the well.
6. Reservoir: the choice of the node in the reservoir allows us to determine the effect of reservoir depletion on well performance. **[2]** (**Figure II-3**)

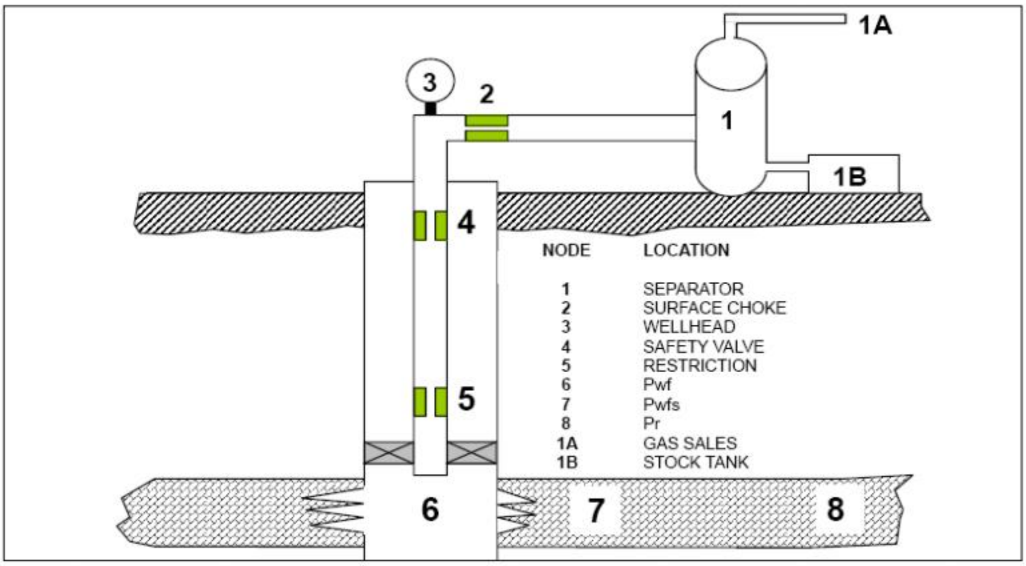


Figure II-3: Various node compositions. [2]

II.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. **[2]**

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. **[6]** (**Figure II-4**)

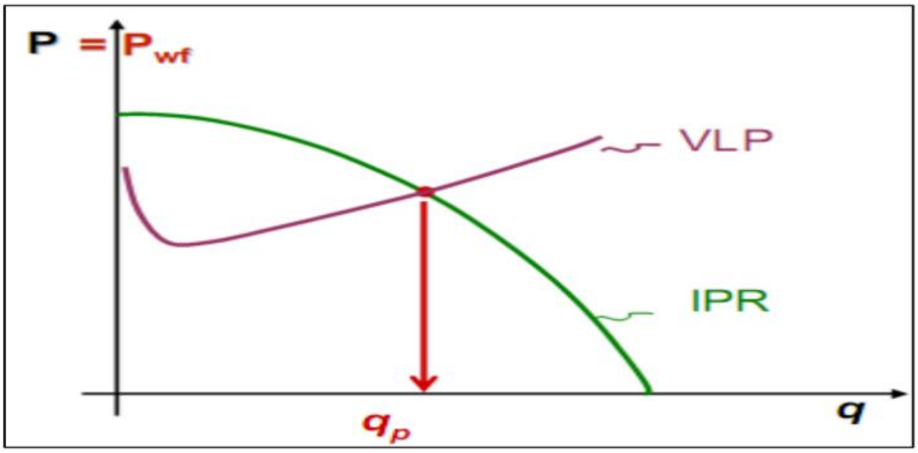


Figure II-4: Operating point. [2]

The production system is then segmented into two parts:

1. **Inflow**: This segment includes all components from the reservoir to the node.
2. **Outflow**: This segment encompasses all components from the node to the separator.

Upon the selection of the node (**Figure II-5**), the pressure at this node is ascertained by:

- For Inflow:

$$Pnode = Pu - \Delta Pu \quad \textbf{(II-1)}$$

- For Outflow:

$$Pnode = Pd - \Delta Pd \quad \textbf{(II-2)}$$

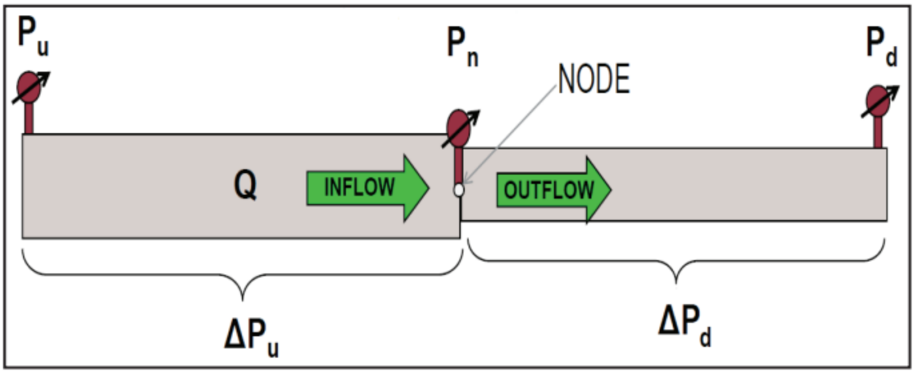


Figure II-5: Node pressure. [2]

The intersection point of the Inflow and Outflow curves on a shared graph signifies the operational point of the well. This specific point is instrumental in determining the flow capacity of the production system. **[2]** (**Figure II-6**)

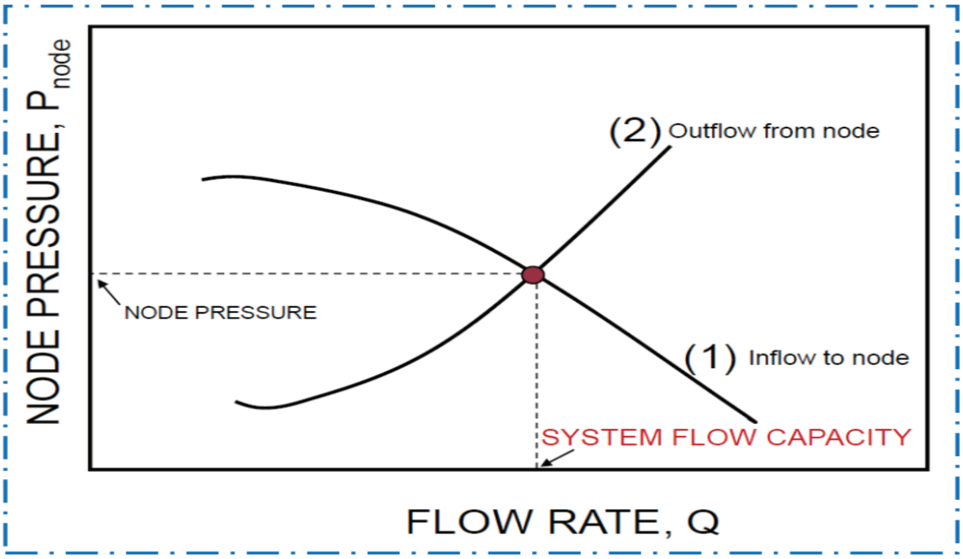


Figure II-6: Well performance. [2]

II.3.3 Inflow Performance Relationship:

The formulation of the Inflow Performance Relationship (IPR) curve is crucial in the realm of production (**Figure II-7**). The IPR represents the ability of a well to transport fluid from the reservoir to the surface. This ability is influenced by several factors, such as:

- The nature of the reservoir,
- The pressure within the reservoir,
- The permeability of the formation, and the properties of the fluid.

To facilitate the application of the IPR law, it is essential to take into account the flow type. **[2]**

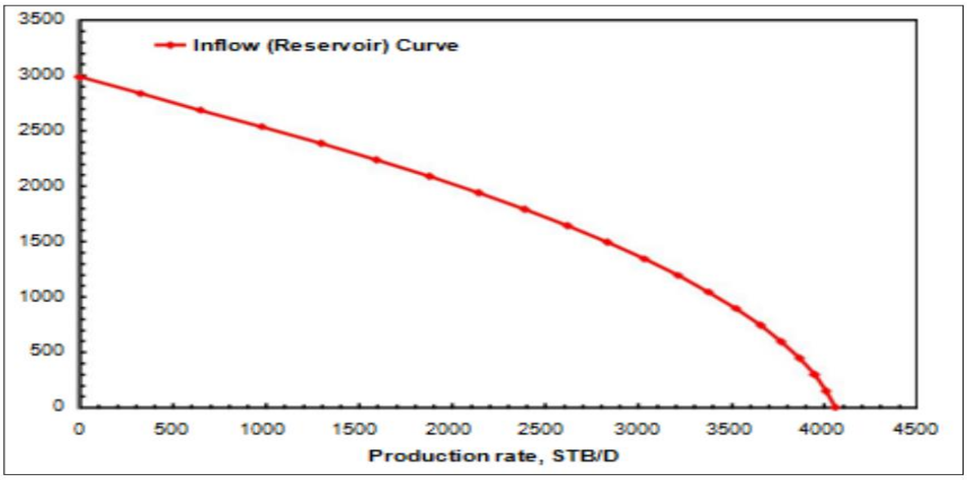


Figure II-7: IPR (Inflow Performance Relationship) curve. [2]

II.3.3.1 Well PI (Darcy's Law):

Single-phase flow within the reservoir is controlled by Darcy’s equation. The Inflow Performance (PI) of a well is also determined by Darcy’s Law. ,

The Productivity Index (PI) is defined as the quantity of barrels produced per day per psi of bottom pressure drawdown. The term bottomhole pressure drawdown refers to the difference between the static and dynamic bottom pressures.

The following equation provides a simplified representation:

$$\mathrm{IP} = \frac{\mathrm{Q}}{\mathrm{P_{Ws}} - \mathrm{P_{Wf}}} \quad \textbf{(II-3)}$$

Where:

- **PI:** the productivity Index (in bbl/d*psi).
- **Q:** the produced flow rate (in barrels per day).
- **Pws:** the Static bottom pressure (in psi).
- **Pwf:** the dynamic bottomhole pressure (in psi).

When gas is liberated from oil, a two-phase flow ensues in the vicinity of the well. This occurrence leads to a reduction in the productivity index.

To predict the well’s characteristic curve when the bottomhole pressure falls below the bubble point pressure, a new theory has been proposed. **[2]**

II.3.3.2 Single-phase flow in the reservoir (Darcy equation):

A flow is classified as single-phase when the flowing bottomhole pressure (Pwf) exceeds the bubble point pressure (Pb) that is then Pwf > Pb. Darcy’s law can be used to define this type of flow. **[2]**

$$\mathbf{Q} = \frac{\mathbf{7.08 \times 10^{-3} \times kh(P_r - P_{wf})}}{\boldsymbol{\mu_o \beta_o} \left[\mathbf{ln}\left(\frac{\mathbf{r_e}}{\mathbf{r_w}}\right) - \mathbf{0.75} + \mathbf{s}\right]} \quad \textbf{(II-4)}$$

Where :

- **Q :** Oil rate in (stb/d)
- **Pr**: Reservoir pressure in (kg/cm2)
- **Pwf:** The dynamic bottomhole pressurein (kg/cm2)

- **k:** Permeability in (md)
- **h:** Reservoir height in (m)
- $\boldsymbol{\mu_o}$**:** Oil viscosity in (C_P)
- $\boldsymbol{\beta_o}$**:** Oil volume factor
- $\boldsymbol{r_e}$**:** Damaged zone radius in (m)
- $\boldsymbol{r_w}$**:** Non damaged zone radius in (m)
- **S:** Skin factor

The typical IPR of a single-phase liquid is shown in this graph (**Figure II-8**):

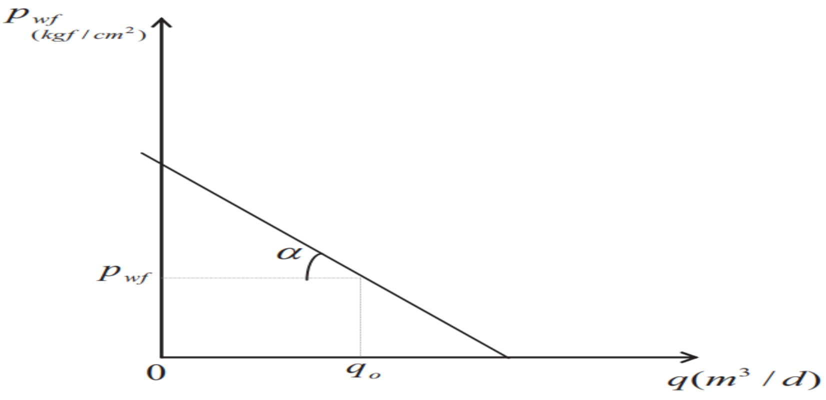


Figure II-8: The IPR for a single-phase liquid. [2]

II.3.3.3 Two-phase flow in the reservoir (vogel's equation):

The two-phase flow, encompassing both liquid and gas, is characterized by the Inflow Performance Relationship (IPR) curve. This curve is defined by Vogel's equation, which is particularly applicable to an oil reservoir where gas is present and the reservoir pressure (Pr) is less than the bubble point pressure (Pb), (Pr < Pb). **[2]**

The equation was derived by Vogel as follows:

$$\frac{Q_o}{Q_o(max)} = 1 - 0.2\left(\frac{P_{wf}}{P_r}\right) - 0.8\left(\frac{P_{wf}}{P_r}\right)^2 \quad \textbf{(II-5)}$$

In other words i.e. for a given test throughput, we determine:

$$Q_o = \frac{Q_o(max)}{1-0.2\left(\frac{P_{wf}}{P_r}\right)-0.8\left(\frac{P_{wf}}{P_r}\right)^2} \quad \textbf{II-6)}$$

- $\boldsymbol{Q_o}$**:**flow rate corresponding to $\boldsymbol{P_{wf}}$

- $\boldsymbol{Q_o(max)}$**:** Maximum flow rate corresponding to zero dynamic pressure **($\boldsymbol{P_{wf}}$=0) (AOF)**
- **Pwf:** The dynamic bottomhole pressure
- **Pr**: Appoximate reservoir pressure

Vogel’s relationship is often viewed as a universal solution for reservoirs operating under the bubble point that is within a dissolved gas regime. When the production is above the bubble point, Darcy’s standard equation remains applicable due to the linear progression of pressure as a function of flow rate, a concept often referred to as the Inflow Performance (IP) method. Over time, numerous modifications have been introduced to Vogel’s equation to accommodate various scenarios. **[2]**

II.3.3.4 Fetkovich method:

Fetkovich provides a method for determining inflow performance for oil wells that employs the same equations used to analyze gas wells.

The equation used by Fetkovich is as follows:

$$q_0 = C.\left({\bar{P}_R}^2 - {P_{wf}}^2\right)^n \quad \textbf{(II-7)}$$

Where:

q_0: Production rate.

$\bar{P}_R$: Average reservoir pressure.

P_{wf}: flowing wellbore pressure.

C: Flow coefficient.

n: Exponent depending on well characteristics.

Fetkovich examined 40 test cases and found that the value of (n) ranged between 0.568 and 1.00.

Since we have two unknowns (C and n) we must perform at least two tests to determine them.

II.3.4 Vertical Lifting Performance curve:

The Vertical Lifting Performance (VLP) curve is instrumental in illustrating the capability of the system and its impact on the flow, contingent on the flow rate. This influence on the flow is also a function of the head losses produced. The dynamic bottom pressures, computed through correlations, present the vertical head losses as a function of varying flow rates.

The Vertical Lift Performance Relationship (VLP), also referred to as Outflow, characterizes the fluctuation in pressure at the bottomhole, contingent on the flow rate. The VLP is influenced by numerous factors, encompassing the properties of the PVT (Pressure, Volume, Temperature) fluid, the well's depth, the diameter of tubing, and the flow rate. Additional factors include the tubing diameter, surface pressure, water cut, and the gas proportion. The VLP delineates the progression of the flow from the well's bottom to its top. The Inflow Performance Relationship (IPR) and the VLP correlate the wellbore flow pressure with the surface production rate. **[2]** (**Figure II-9**)

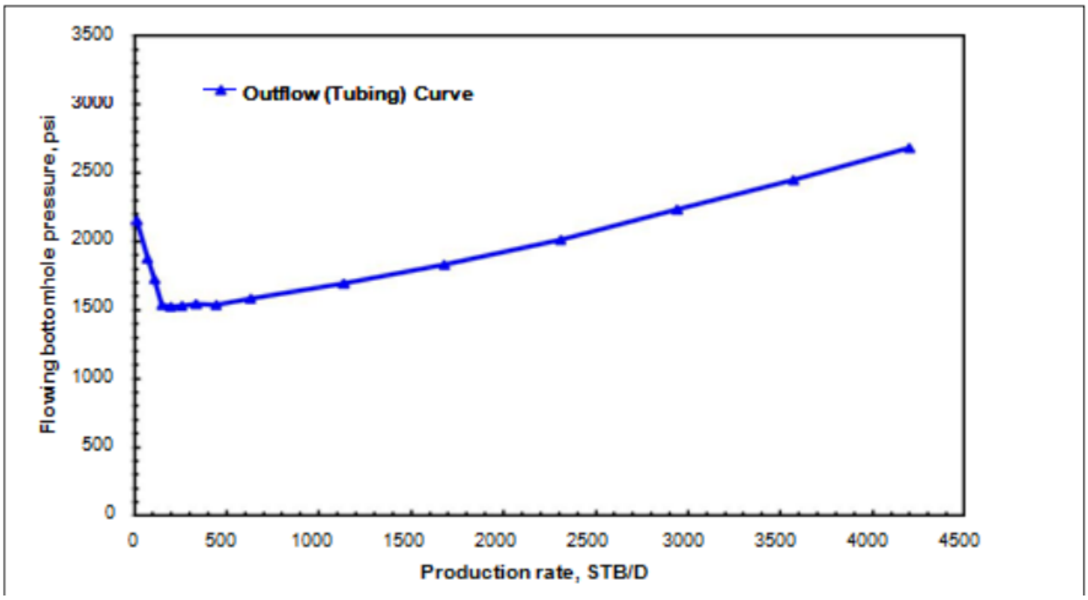


Figure II-9: VLP (Vertical Lifting Performance) curve. [2]

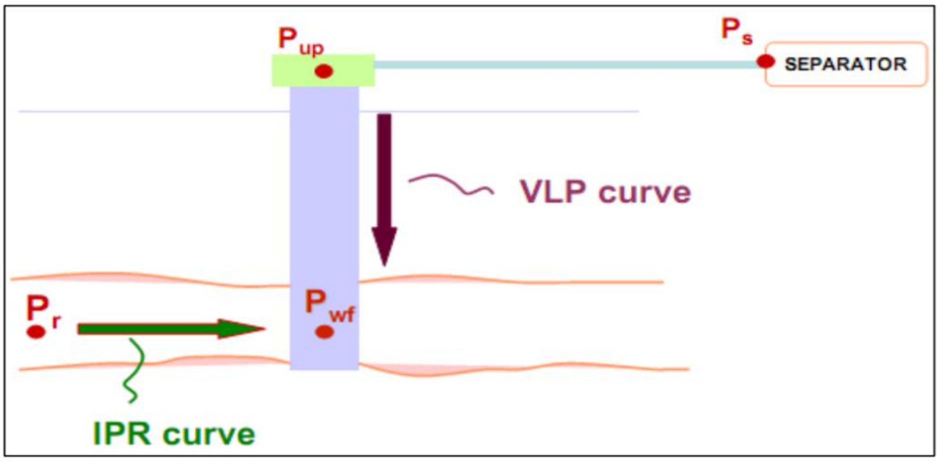


Figure II-10: IPR and VLP in a production system. [2]

The operational point of a well is determined by the intersection of the Inflow Performance Relationship (IPR) and the Vertical Lift Performance Relationship (VLP). The flow rate and the bottomhole pressure are relative to the well's actual production under specific operating conditions. These conditions include reservoir pressure (Pr), productivity index (PI), water cut (WC), gas-oil ratio (GOR), and tubing diameter, among others. **[2]**

II.4 Tubing Performance Curves (TPC) in oil and gas fields:

Tubing Performance Curves (TPC) represent the capacity of the tubing to transport fluids from the bottomhole to the wellhead. The TPC curve delineates the fluid flow rate as a function of the dynamic bottomhole pressure, primarily based on the computation of pressure losses in the tubing. Each point on the TPC curve indicates the pressure required at the bottomhole (Pwf) to yield a specific flow rate at the surface.

To construct this outflow performance curve, it is essential to comprehend and recognize the types of flow in the vertical pipe (tubing). **[1]**

II.4.1 Evolution of studies on Outflow Curves:

In 1939, E.C. Babson initiated the study of vertical multiphase flow, which was continued by W.E. Gilbert from 1939 to 1940. However, Gilbert's work was not published until 1954. His most significant contribution was the introduction of a 'pressure gradient' graph, which plotted pressure against depth.

In 1952, Poettmann and Carpenter revolutionized the field by developing correlations instead of pressure gradient curves. This marked the first mathematical approach that yielded satisfactory results across a broad range of flow conditions. The pressure gradient curves derived from these correlations have been extensively utilized in the design of gas-lift installations.

In recent times, several other correlations have emerged. The most notable among these are those proposed by Hagedorn & Brown, Orkiszewski, and Ros. **[1]**

II.5 Flow Correlations for Different Flow Regimes:

Pipe flow correlations are widely utilized in industry, and they are included in the majority of nodal analysis software packages. Each of these flow correlations has an applicable range based on many factors such as tube diameter, oil gravity, and gas liquid ratio.

The primary reasons for applying multiphase flow correlations are to estimate liquid holdup and pressure gradient, and they have also been employed in worst case discharge (WCD) calculations to anticipate pressure and temperature changes in wellbore. Identifying flow regimes is crucial for multiphase flow studies and requires a specific correlation. **[1]**

II.5.1 Two-Phase Flow Regimes:

Flow regime or flow pattern is essentially a qualitative description of how the two phases are distributed in the well pipe. (**FigureII-11**) illustrates four types of flow regimes:

- Bubble flow: The bubbles of gas are dispersed in an uninterrupted liquid phase.
- Slug flow: With a high gas rate, the bubbles merge into greater bubbles that eventually fill almost the whole pipe cross section. Slugs of liquid that contain smaller bubbles of gas are between the large gas bubbles.
- Churn flow: As gas rate increases even further, the larger gas bubbles present instability and they start collapsing. Therefore, with both phases dispersed, this flow regime can be considered as chaotic.
- Annular flow: At a very high gas rate, gas becomes the continuous phase. Gas itself flows in the core of the pipe, while liquid flows in a homogenous thin film on the pipe wall.

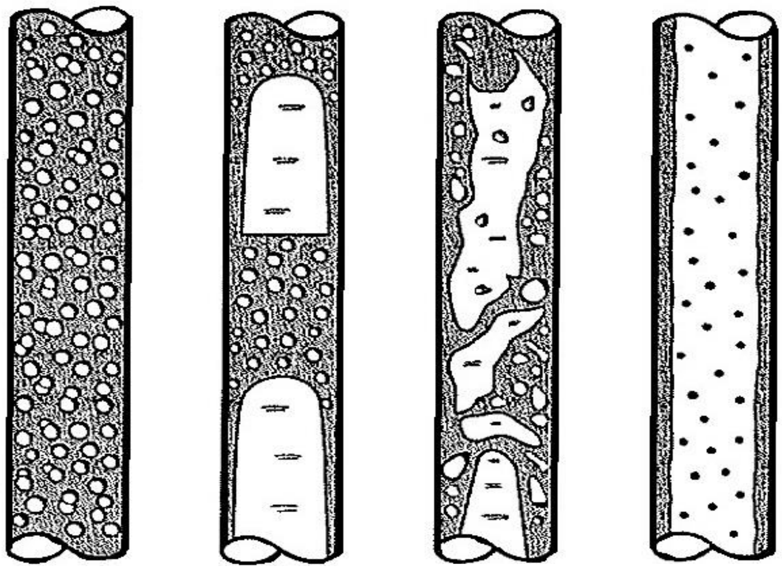


Figure II-11: Gas-liquid flow regimes in vertical pipes.

II.5.2 Various TPC correlations in oil and gas fields:

In Algeria, four correlations are predominantly employed to estimate the pressure profile in a well: Duns & Ros, Hagedorn & Brown, Orkiszewski, and Beggs & Brill. The applicability of these correlations depends on factors such as tubing diameter, oil density, Gas-Liquid Ratio (GLR), and two-phase flow with or without water-cut. These correlations are considered effective if they exhibit a relative error of 20% or less. **[1]**

1. **Duns & Ros correlation:**

This correlation is formulated for a vertical flow of a gas-liquid mixture in a well. It is applicable to a broad spectrum of oil and gas mixtures and flow regimes. While it is primarily designed for dry oil/gas mixtures, it can also be applied to wet mixtures with suitable correction. For water contents less than 10%, the Duns & Ros correlation (with a correction factor) has been used in bubble, plug, and foam regions. The performance of this correlation is evaluated based on the following factors:

- Tubing Diameter: The predicted pressure drop aligns closely with actual measurements for tubing diameters between 1 and 3 inches.
- Oil Density: Reliable pressure profile predictions are obtained for a wide range of oil densities (13-56 API).
- GLR: The pressure drop is near predictions across a wide GLR range, with errors becoming particularly large for GLR above 5000.

- Water-cut: This correlation is not applicable for multiphase flow of oil, water, and gas mixture. However, it can be used with a correction factor as indicated above. **[1]**

2. **Hagedorn & Brown correlation:**

This correlation was developed using data obtained from a depth of 1500 ft. The performance of this correlation is evaluated based on the following factors:

- Tubing Diameter: Pressure losses are anticipated for diameters between 1 and 1.5 inches, which is the range in which the experimental investigation was conducted. For diameters greater than 1.5 inches, the pressure drop is approximately as predicted.
- Oil Density: The Hagedorn & Brown correlation predicts the pressure profile for heavy oils (13-25 API) and light oils (40-56 API).
- GLR: The pressure drop is approximate to the forecasts for GLR less than 5000.
- Water-cut: The accuracy of pressure profile forecasts is generally good for a wide range of water-cuts. **[1]**

3. **Orkiszewski correlation:**

The Orkiszewski correlation, an extension of the work of Griffith & Wallis, is valid for different flow regimes. The performance of this correlation is evaluated based on the following factors:

- Tubing Diameter: The correlation works well for diameters between 1 and 2 inches. The pressure drop is approximately as expected for tubing diameters over 2 inches.

This correlation predicts the pressure profile for oil densities between 13-30 API. For oil densities greater than 5000, the predicted pressure drop is approximately accurate. The Orkiszewski correlation is highly accurate for GLR below 5000, but errors become significant (> 20%) for GLR above 5000. The correlation also predicts the pressure drop with good accuracy for a wide range of water-cuts. **[1]**

4. **Beggs & Brill correlation:**

This correlation was developed for inclined wells and pipelines in rugged terrain. The performance of this correlation is evaluated based on the following factors:

- Tubing Diameter: The pressure drops are accurately estimated for the range in which the experimental study was carried out, between 1 and 1.5 inches. For tubing diameters greater than 1.5 inches, the pressure loss is as predicted.
- Oil Density: Good performance is obtained over a wide range of oil densities.
- GLR: In general, an approximate pressure drop is obtained with an increase in GLR. Errors become particularly significant for GLR above 5000.
- Water-cut: The accuracy of pressure profile forecasts is generally good up to about 10% water-cut. **[1]**

In general, the Orkiszewski and Hagedorn & Brown correlations are valid for vertical wells, with or without water-cut, and should therefore be considered as the first choice in these wells. As mentioned previously, the Duns & Ros correlation is not applicable for wells with water-cut, and should be avoided for such cases. The Beggs & Brill correlation is applicable for inclined wells, with or without water-cut, and is currently the best choice available for deviated wells. However, the method can also be used for vertical wells as the last choice. **[1]**

II.5.2.1 Choice of correlation:

The best correlation suitable for a certain well is chosen based on the conditions of application that are close to our case. The most suitable correlation is determined by the following steps:

- Introduce the well data by placing the node at the bottom of the well.
- Plot the pressure drop curve in the tubing as a function of the well depth by introducing a gauge (pressure recorder).
- Plot the pressure drop curve in the tubing as a function of well depth for each correlation.
- The most appropriate correlation is the one that gives a tubing pressure profile close to that measured. **[1]**

II.5.2.2 Correction of the selected correlation:

Despite selecting the most suitable correlation, there can occasionally be minor errors. To correct these, a multiplication factor, denoted as L, is introduced to align the correlation curve with the actual curve. This factor typically ranges between 0.85 and 1.15. **[1]**

II.6 Introduction to the optimization (PIPESIM software):

PIPESIM, a Pipeline Simulator, is a software tool developed by Schlumberger. It enables the analysis of performance for both producing and injecting wells, based on a detailed description of the effluent flow process from the reservoir to the surface separator. This flow process is divided into three stages:

- Bottom flow (through the reservoir).
- Flow through the completion (liner, tubing, and annulus).
- Surface flow (through the collection network, separator). **[1]**

II.6.1 Applications of PIPESIM software:

The PIPESIM software is utilized for:

- Optimization of well equipment.
- Analysis of well performance.
- Analysis of well collection and separation networks.
- Optimization of production systems.
- Analysis and design of horizontal and multilateral wells.
- Optimization of recovery systems. **[1]**

II.6.2 Data required for PIPESIM usage:

The data required to use PIPESIM includes:

- Completion data (well data sheet, monitoring data).
- Petrophysical data.
- Geological data reports.
- PVT, DST, Build up, Gauging tests data.
- Various reports on measurements and operations conducted on the wells. **[1]**

II.6.3 Optimization of Parameters for Gas Lift Wells:

This section focuses on optimizing parameters that influence gas lift efficiency. The parameters considered include:

- Liner diameter.
- Gas-lift injection rate.
- Injection mode (annular or concentric).

- Injection point depth.
- Nozzle diameter. **[1]**

II.6.4 Overview of PIPESIM Software:

PIPESIM, designed by Schlumberger, is a simulator that performs the following tasks:

- well performance analysis.
- Production optimization.
- Well equipment optimization.
- Well network analysis.
- Analysis of multilateral wells.

By separating the modeling of each component of the production system, PIPESIM enables the user to effectively manage and optimize the system. PIPESIM ensures that the calculations are as accurate as possible. Once a model of the system has been set to the true field data, PIPESIM can be used with confidence to model the production system, simulate its behavior, and study its sensitivity to different parameters. **[1]**

II.6.5 The procedure for modeling and simulating wells using PIPESIM:

- ❖ Construction of a physical model.
- ❖ Input data (system data).
- ❖ Choice of correlation for vertical flow. **[1]**

Case Study

Chapter III Case Study

III.1 Presentation of Hassi-Messaoud field:

III.1.1 Introduction:

Hassi-Messaoud field, situated in the Berkine Basin, stands as the largest oil field in Algeria and across the entire African continent. Estimated reserves of the deposit are approximately 9 billion barrels of high-quality crude oil. This field spans an approximate area of 2500 square kilometers. Discovered in 1956 and subsequently brought into widespread production by 1958, the Hassi-Messaoud deposit has persisted for over 50 years, continuously supplying Algeria with this vital natural resource, crude oil. Substantial investments have been and will continue to be made to extract the maximum amount of oil and consequently enhance the ultimate recovery process. (**Figure III-1**)

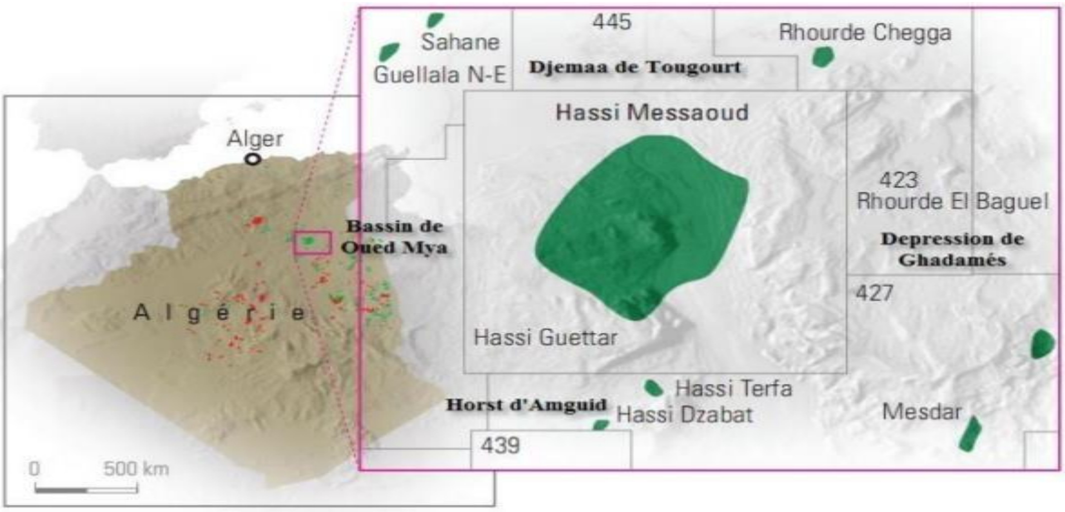


Figure III-1 : Geographical position of Hassi-Messaoud.

III.1.2 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.

III.1.3 Reservoir description:

The Hassi Messaoud deposit has a depth ranging from 3100 to 3380 m and a thickness of up to 200 m. It comprises three sandy reservoirs of Cambrian age, resting directly on the granitic basement. It is represented by a sandy series, part of which is affected by post-Paleozoic erosion in the central part of the field (**Figure III-2**). It subdivides from top to bottom into:

- **Ri**: Isometric zone with a thickness of 45 m, mainly consisting of fine-grained quartzite and tigillites. It corresponds to drain D5.
- **Ra**: Anisometric zone with an average thickness of approximately 120 m composed of medium to coarse-grained sandstone with silico-argillaceous cement. It is subdivided into drains, from bottom to top: D1, ID, D2, D3, D4.
- **R2**: Sandy series with clayey cement, with an average thickness of 80 m.
- **R3**: Approximately 300 m in height, it is a very coarse to microconglomeratic sandy series, very clayey, resting on the granitic basement encountered at a depth below 4000 m, which is a pink porphyroid granite. It is divided into two sublevels; R2c and R2ab.

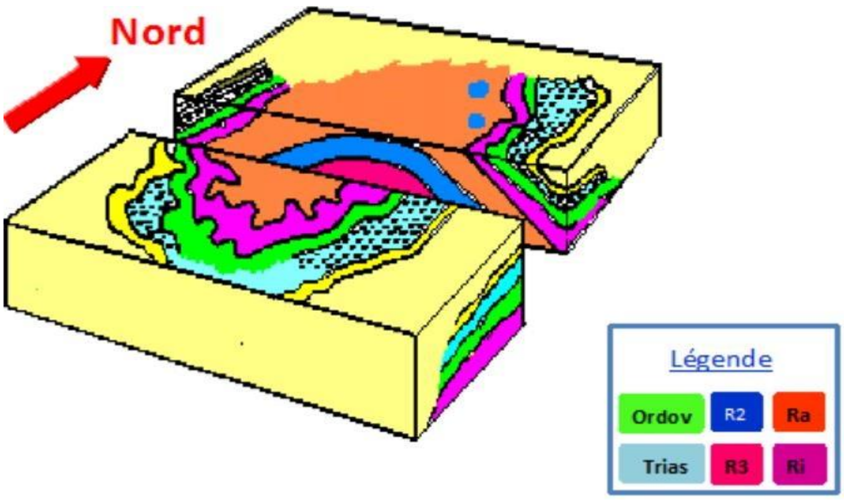


Figure III-2 : Block diagram of the geological discordance beneath the Hercynian unconformity.

III.1.4 Hassi-Messaoud field situation :

III.1.4.1 Geographical situation:

The HMD field is located 850 km south/southeast of Algiers and 350 km from the Tunisian border. In terms of geographic coordinates of the deposit, it is delimited as follows:

- To the north by latitude 32°15.
- To the south by latitude 31°30.
- To the west by longitude 5°40.
- To the east by longitude 6°35.

III.1.4.2 Geological situation:

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 km². 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.

III.1.4.3 Field zoning and well numbering:

The evolution of well pressures in relation to production has enabled the subdivision of the Hassi-Messaoud reservoir into 25 zones, referred to as its production zones, with variable extents. These zones exhibit relative independence and correspond to a collection of wells communicating among themselves rather than with those in neighboring zones. Each zone demonstrates distinct reservoir pressure behavior. Wells within the same zone collectively drain a well-established quantity of in-place oil. However, it is imperative to note that pressure factor alone cannot serve as the sole criterion for characterizing these zones. The Hassi-Messaoud field is divided into two distinct sections: the northern zone and the southern zone, each assigned its numerical designation by the initial detecting companies of the field (**Figure III-3**).

1. Northern Field:

This field includes a geographical numbering system supplemented by a chronological numbering system, for example, Omn 45.

- **O**: Ouargla permit.
- **m**: the area of the oil zone is 1600 km².
- **n**: the area of the oil zone is 100 km².
- **4**: abscissa and **5**: ordinate.

2. Southern Field:

This field is primarily chronological, supplemented by a geographical numbering system based on abscissas and ordinates at intervals of 1.250 km, harmonized with Lambert coordinates.

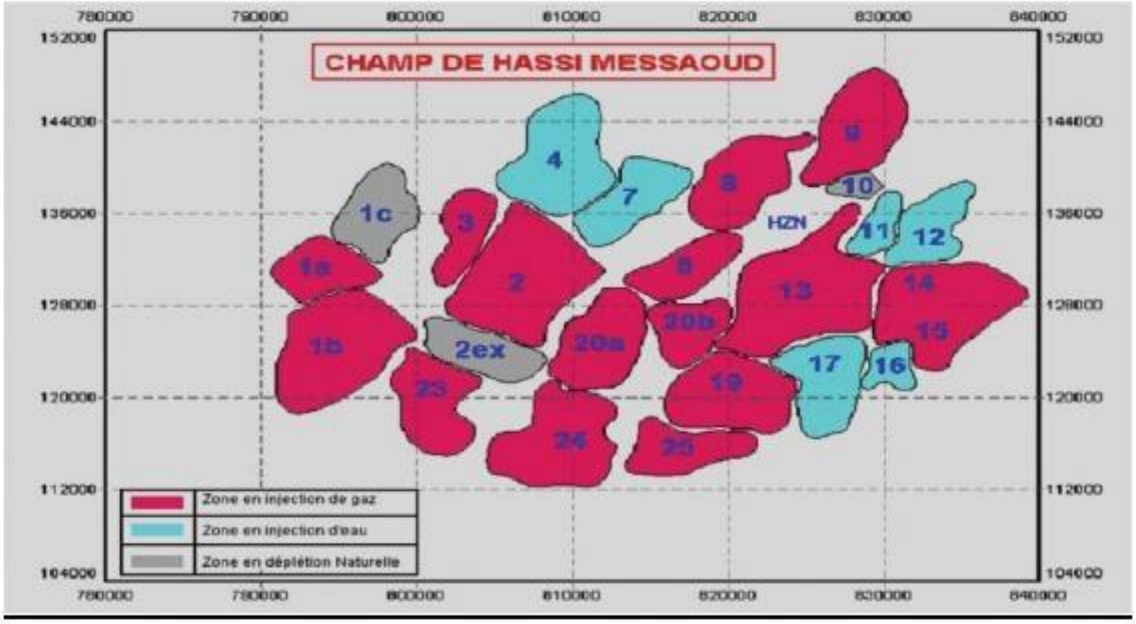


Figure III-3: Zoning the Hassi-Messaoud field.

III.1.4.4 The peripheral fields of hassi-messaoud:

The peripheral fields of Hassi-Messaoud are distributed according to their geographical positions as follows:

- Southern periphery: Hassi Guettar (HGA), Hassi Guettar West (HGAW), Hassi Khbiza (HKZ), Hassi Terfa (HTF), and Hassi D'Zabat (HDZ)
- Northern periphery: Rhourde Chegga (RDC), Garet Benchentir (OL)
- Northern upside of Hassi Messaoud.
- Eastern periphery: Bhiret Aissa (BRA) and Draa Eddaoui (DAD) fields.

III.2 Work stages:

III.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 lifetime.

III.2.2 Data collection:

From the database, we obtain the results of the various tests conducted on the selected well. The technical data of this well, including information on completion, tubing dimensions, and perforation depth, are also essential.

Table III-1 : Well technical data.

Data Required			
Fluid data	**Reservoir data**	**Completion data**	**Surface data**
Fluid Model	Dynamic bottom pressure	Reservoir temperature	Head pressure
Fluid properties	Flow	Tubing length	wellhead temperature
GOR (Rs)	Reservoir temperature	Tubing ID, ED	
Gas density	IPR curve	Injection valve dimensions	
Water Density	/	Perforation dimensions.	
API (dead oil density)	/	/	

III.2.3 Well history HGAS3 :

Well HGAS3 is a vertical oil producer drilled on 02/12/2008 (end of drilling date) to a depth of 3467 meters. The well is completed with a Cemented Perforated Liner (LCP) and has a perforated interval of 80 meters. The gas lift commencement date is 02/04/2024.

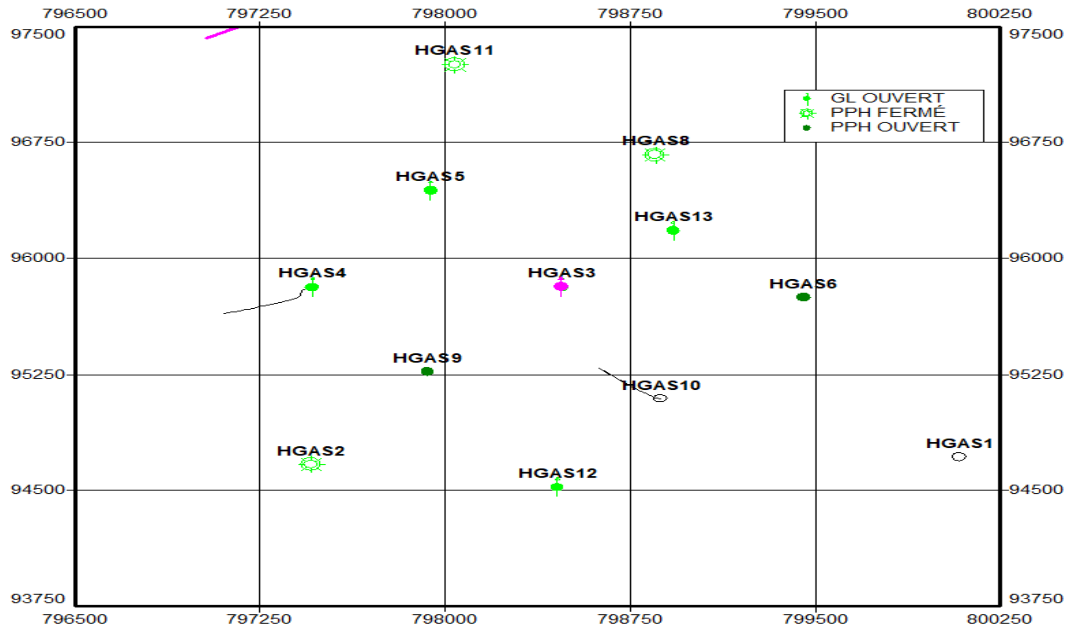


Figure III-4: Location map of HGAS3 well.

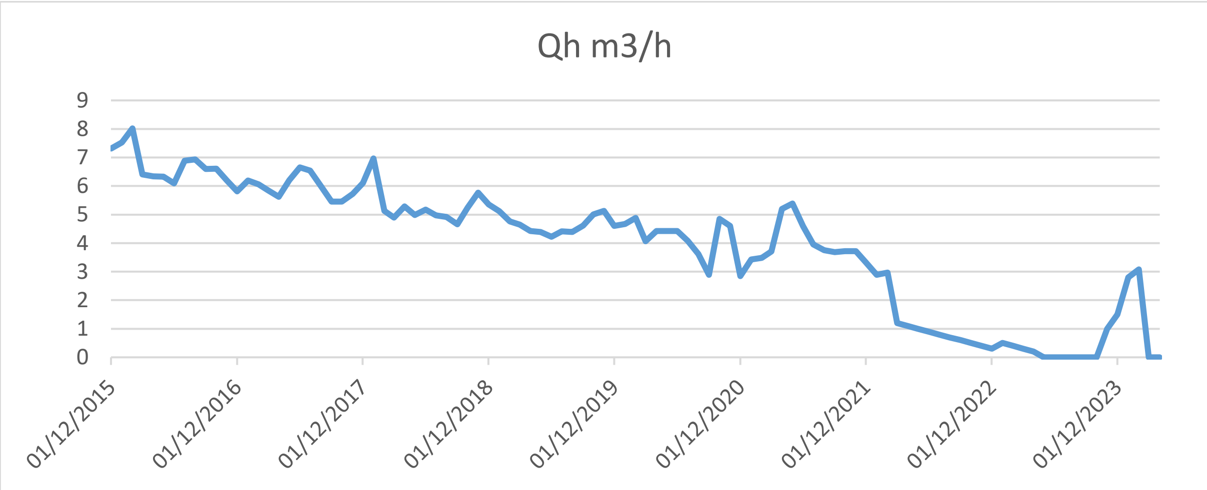


Figure III-5: HGAS3 Well Production Profile.

Table III-2 : HGAS3 Well test parameters.

Test	Date	PG (kg/cm^2)	PFD (kg/cm^2)	PT (kg/cm^2)	Flow (m3/h)		PI	HKP	HKL	HKL (Hw * Kyz)	Skin	Choke
DST	03/01/2008	420.93	251.36	63	Oil	11.82	3,4	--	-	68.3	-2.45	12.5
BUILD UP	21/05/2020	344.4	185.1	32.3	Oil	4.33	1,7	--	-	80	3.6	9.53
PFD	02/01/2024	186	176	26.45	Oil	3.08	2,964	--	-	-	-	9.53

Table III-3 : The last well operations.

Operations performed on HGAS3		
Start date	**Operations**	**Sub/operations**
11/05/2024	**WIRELINE**	**Control**
02/01/2024	**WIRELINE**	**PFD pressure measurement**
22/12/2023	**WIRELINE**	**Control**
31/10/2023	**SPECIAL_OPERATION**	**Bottom Control + Kick Off**
28/10/2023	**WIRELINE**	**Control**
24/10/2023	**SNUBBING**	**-----**
13/09/2023	**SPECIAL_OPERATION**	**Clean out with Reformat**
10/08/2023	**WIRELINE**	**Drift**
21/05/2023	**SPECIAL_OPERATION**	**Reformat Clean Out**
05/05/2023	**WIRELINE**	**Drift**
10/03/2023	**SPECIAL_OPERATION**	**Clean out with Reformat**

III.2.4 Well problematic:

Our well suffers a decline in production leading to its cessation, attributed to a drop in formation pressure to 186 bar. This decline coincided with an increase in the vertical flowing pressure gradient, driven by a reduced gas-to-liquid ratio (GLR) indicating minimal formation gas content. Consequently, the flowing bottomhole pressure (FBHP) closely matched the static bottomhole pressure (SBHP), indicating inadequate drawdown to sustain flow, rendering it impossible to produce fluid without an artificial lift method.

In addition to that, our well underwent other minor problems such as various deposits of sand, salt…etc.

- **Flow rate investigation:**

This test measures the production rate. Additionally, it allows us to obtain other characteristic parameters such as the Gas-Oil Ratio (GOR), oil temperature, and water salinity. The results are presented in the table:

Table III-4 : Last HGAS3 well gauging.

HGAS3 Well								
Measurement date	Choke Diam (mm)	Separ.Unit	Flow (m^3/h)		GOR	Pressure (kg/cm^2)		
			Oil	Gas		Wellhad pressure	Pipe pressure	Separ pressure
15/01/2020	9	-	10	700.13	145	32.6	13.3	--
11/02/2021	9	1440	8,6	337.76	94	26.2	14.1	--
13/01/2022	9	1440	6,5	246.03	88	22.8	14.7	14.43
14/03/2022	9	1440	1,2	180	73	25	14.7	14.71
09/02/2023	9	-	0,5	125,6	32	23.7	14.9	--
01/04/2024	9	1440	0	0	0	0	0	null

According to the results of Gauge Analysis, the following interpretations can be drawn:

- A significant decrease in flow rate from 10m3/h to 0m3/h demonstrating the severity of this issue.
- The variation in Gas-Oil Ratio (GOR) values is independent of production flow rate values [145--0].

III.2.5 Proposed solutions:

Based on the flow rate analysis and PFD testing, this well exhibits an activation issue. Due to a drop in reservoir pressure and a decrease in Gas-Oil Ratio (GOR), we recommend activating the well through gas lift injection.

Table III-5 : HGAS3 well gauging after optimization.

Measurement date	Choke Diam (mm)	Separ.Unit	Flow (m^3/h)		GOR	Pressure (kg/cm^2)		
			Oil	Gas		Wellhad pressure	Pipe pressure	Separ pressure
After gas lift								
02/04/2024	20	1440	8,1	1806,7	222,7	23,3	14	12,7

III.2.6 Gas-lift optimization:

Gas lift optimization involves the strategic adjustment of gas injection rates with the objective of mitigating gravitational pressure losses within the tubing system in oil and gas fields. The primary goal is to fine-tune the injected gas flow rate to minimize both gravitational pressure losses and fluid friction-induced pressure losses along the tubing casing. Over-injection of gas can lead to diminished oil production as excessively high gas flow rates impede the fluid flow from the formation, primarily due to increased pressure losses. The determination of the optimal gas injection rate (Qginj) hinges upon the comprehensive assessment of head losses occurring within the production column, stemming from two principal sources: gravitational effects on fluid weight and pressure losses incurred from frictional interactions among fluids and tubing.

As depicted in the accompanying figure, the aggregate head losses exhibit a nadir, with gravitational head losses diminishing with increasing gas flow rates while friction-induced losses escalate. The nadir in total pressure losses denotes the optimal Qg inj. Augmentation of gas injection quantities amplifies total pressure losses while concurrently diminishing production rates.

III.2.7 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. (**Figure III-6**)

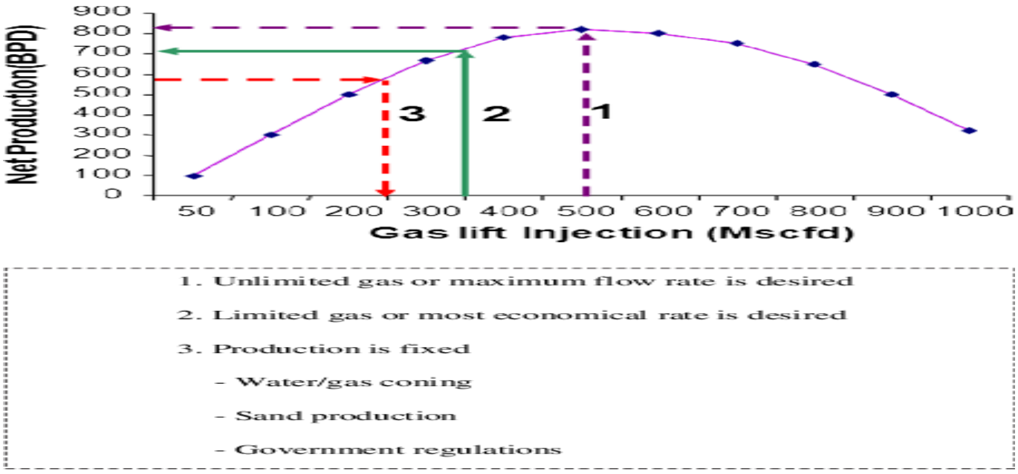


Figure III-6: Gas lift performance curve with condition GAUSSE curve.

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:

a) Inflow Performance Relationship (IPR) Curve:

To delineate the IPR curve (**Figure III-7**), one of the following methodologies is employed:

- Application of the single-phase flow equation (DARCY) when the bottomhole pressure (Pb) is less than the flowing pressure (Pwf).
- Utilization of the two-phase flow equation (VOGEL) when the reservoir pressure (Pr) is less than Pb but greater than Pwf.
- Adoption of the combined DARCY and VOGEL flow equation when Pwf is less than Pb but greater than Pr.

Subsequently, oil flow rates (Qo) are chosen such that they satisfy the condition Qo < Qomax, and the associated dynamic bottomhole pressures (Pwf) are determined. These obtained data points are then graphically represented on a plot of Pwf as a function of Qo, yielding the following graphical representation:

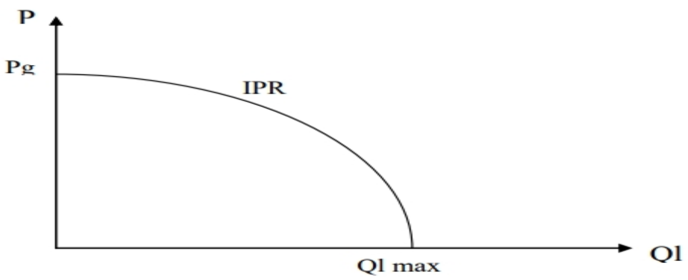


Figure III-7: IPR (Inflow) curve.

b) Vertical Lift Performance (VLP) curve:

The Vertical Lift Performance (VLP) curve, pertaining to outflow conditions, is governed by a multitude of correlations devised for two-phase flow within tubing. These correlations vary in their generality, with some possessing broad applicability while others are tailored for specific contexts. Among the correlations integrated into the PEPESIM software are:

The Poetmann & Carpenter correlation, the Fancher & Brown correlation, No Slip Assumption, Gray (modified), the Hagedorn & Brown correlation, and the Beggs & Brill correlation constitute pivotal considerations in this endeavor. The objective is to identify a correlation that yields results closely aligned with empirical measurements. Accordingly, OLGAS v. 6.2.7 3-Phase correlation is employed to ascertain the dynamic bottomhole pressures (Pfd) corresponding to selected oil flow rates (Ql), with the injection gas flow rate (Qg inj) being set. The resultant data points (Pfd, Ql) are then graphically depicted on the IPR graph and interconnected to delineate the Outflow curve. (**Figure III-8**)

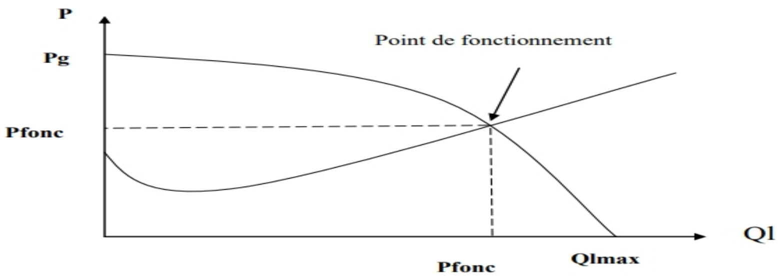


Figure III-8: Inflow and Outflow curve.

c) Construct the other curves of (VLP):

Select other injection rates and plot the corresponding TPC curve as above. This produces the following diagram (**Figure III-9**):

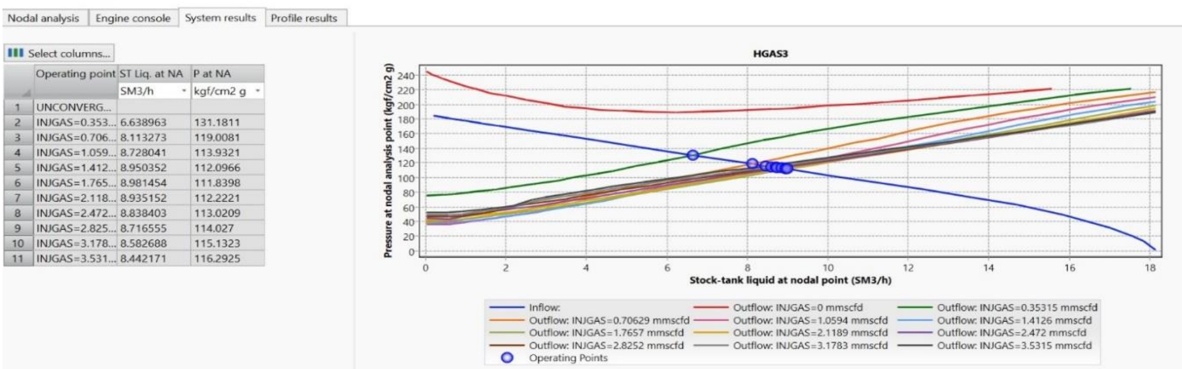


Figure III-9: Curve of different injected gas flow rates.

III.2.8 Overview of PIPESIM software:

The requisite data for utilization within PIPESIM comprises diverse information gleaned from various sources:

III.2.8.1 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.

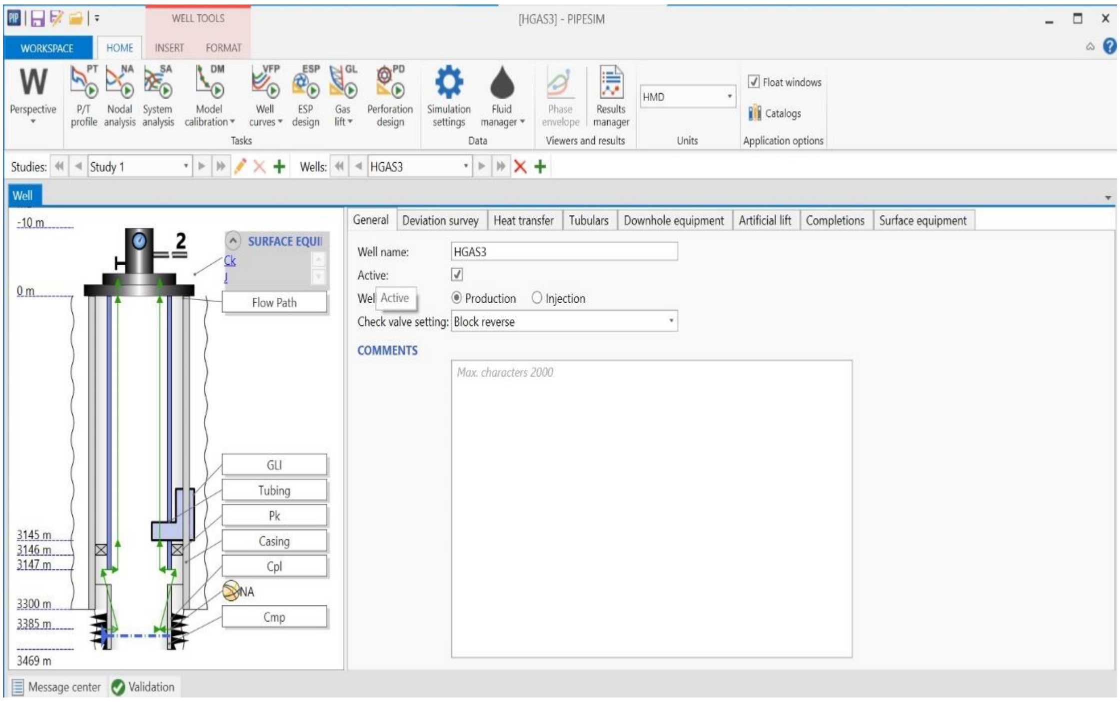


Figure III-10: PIPESIM program interface.

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

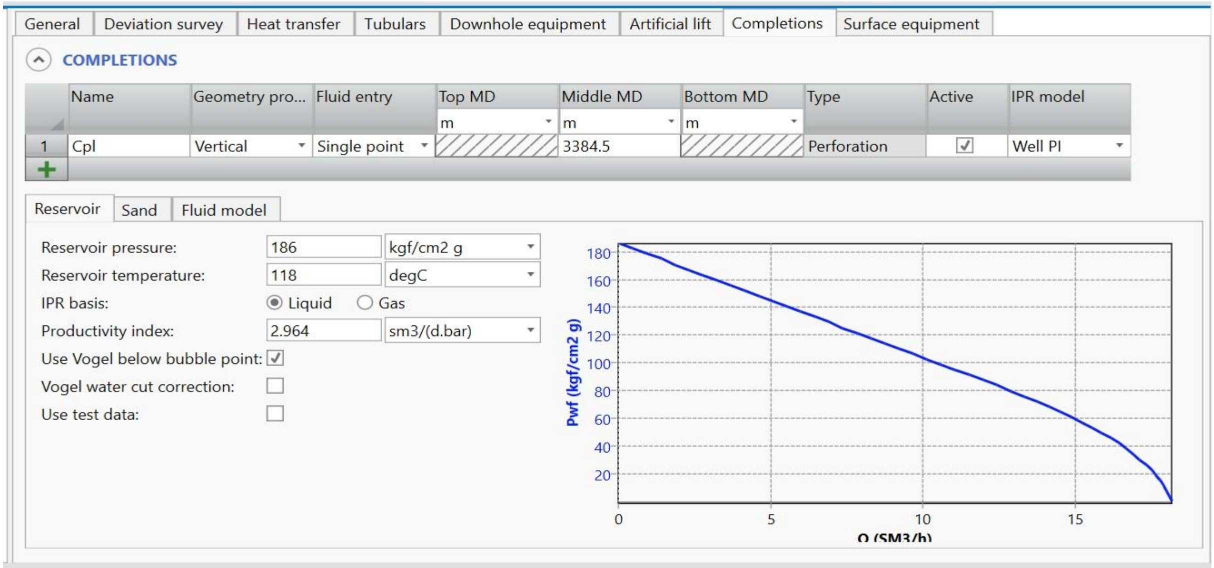


Figure III-11 : Completions parameters.

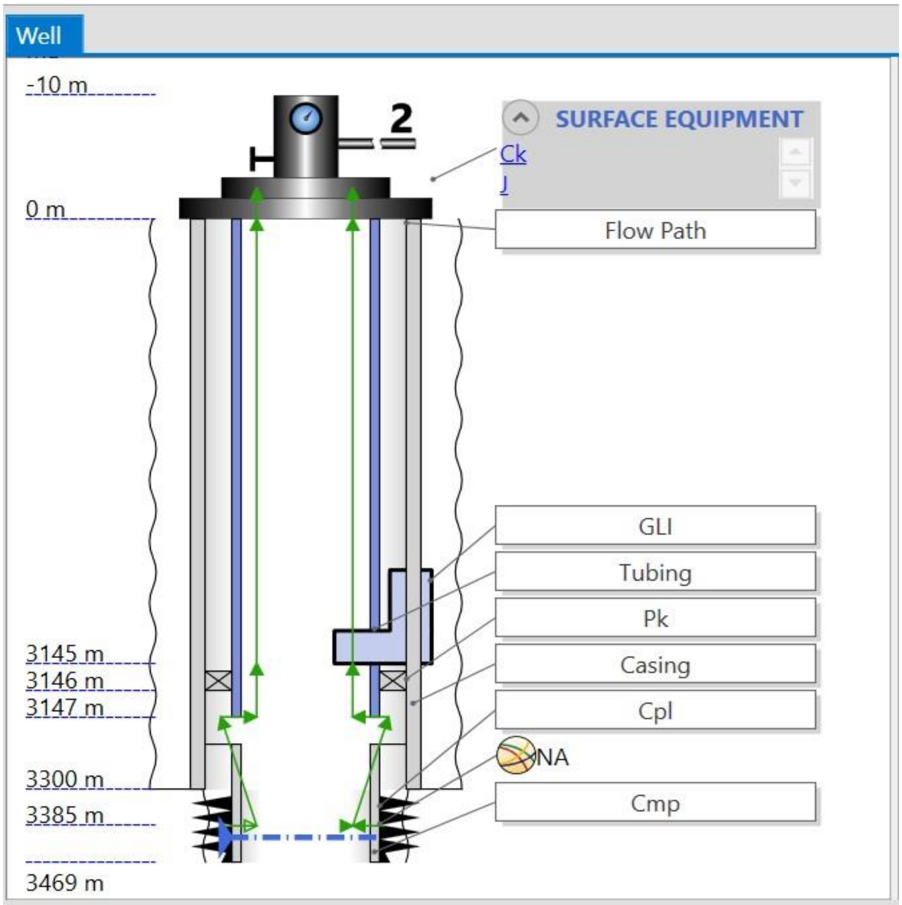


Figure III-12 : The depiction of well completion, as modeled by PIPESIM.

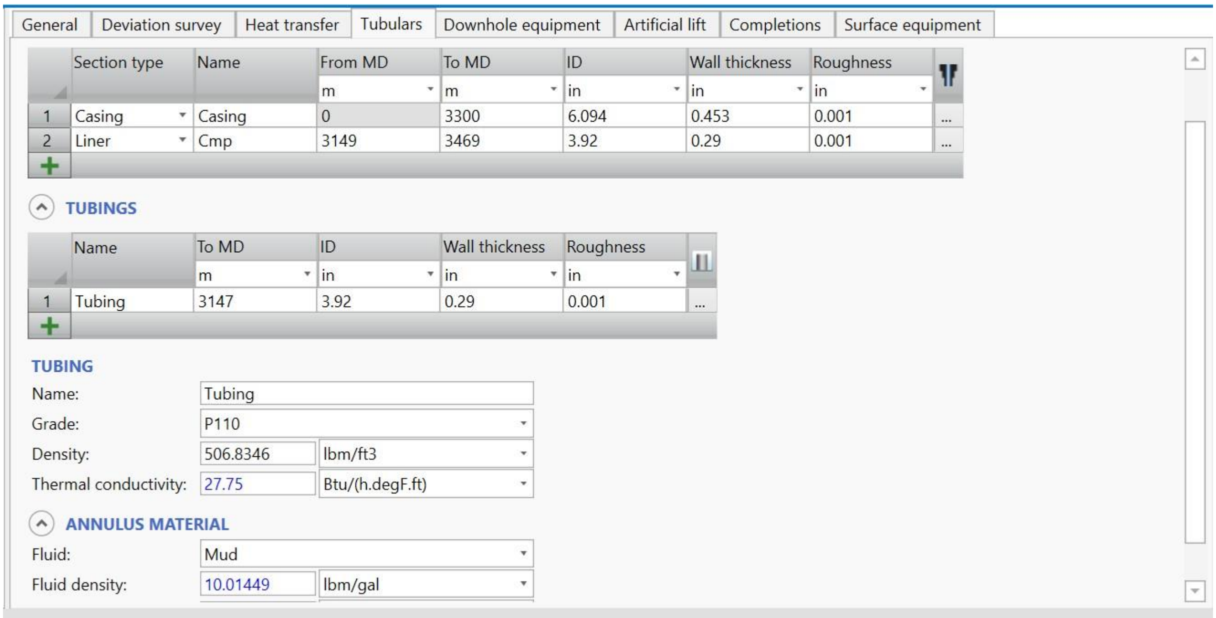


Figure III-13 : Tubular parameters.

III.2.8.2 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:

$$RMS_P = \frac{\sqrt{\sum_{i=1}^{np} (P'i - Pi)^2}}{\sqrt{np}} \quad \text{(III-1)}$$

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

$$RMS_L = \frac{\sqrt{\sum_{i=1}^{nL} (L'i - Li)^2}}{\sqrt{nL}} \quad \text{III-3)}$$

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_{th}observation from the heat transfer models.
- T'i = Measured or observed temperature value for the i_{th} 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.

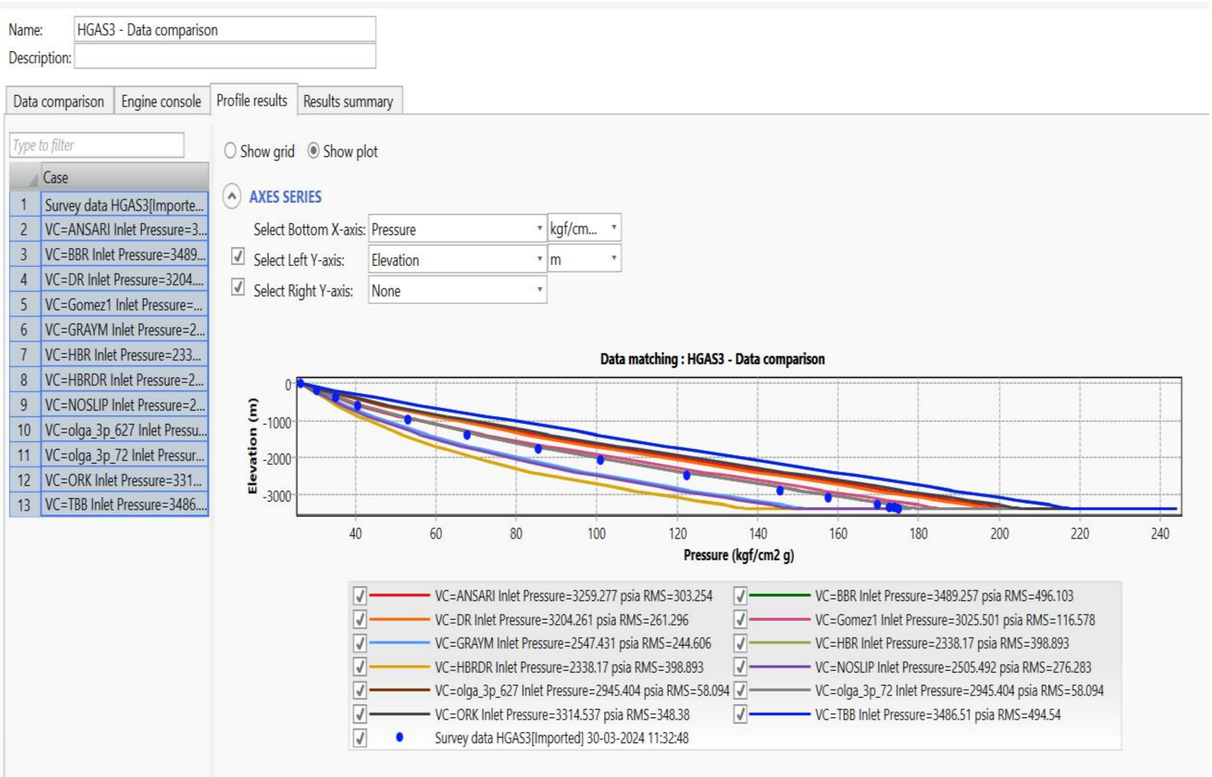


Figure III-14: Multiphase flow correlation comparison sample well HGAS3.

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

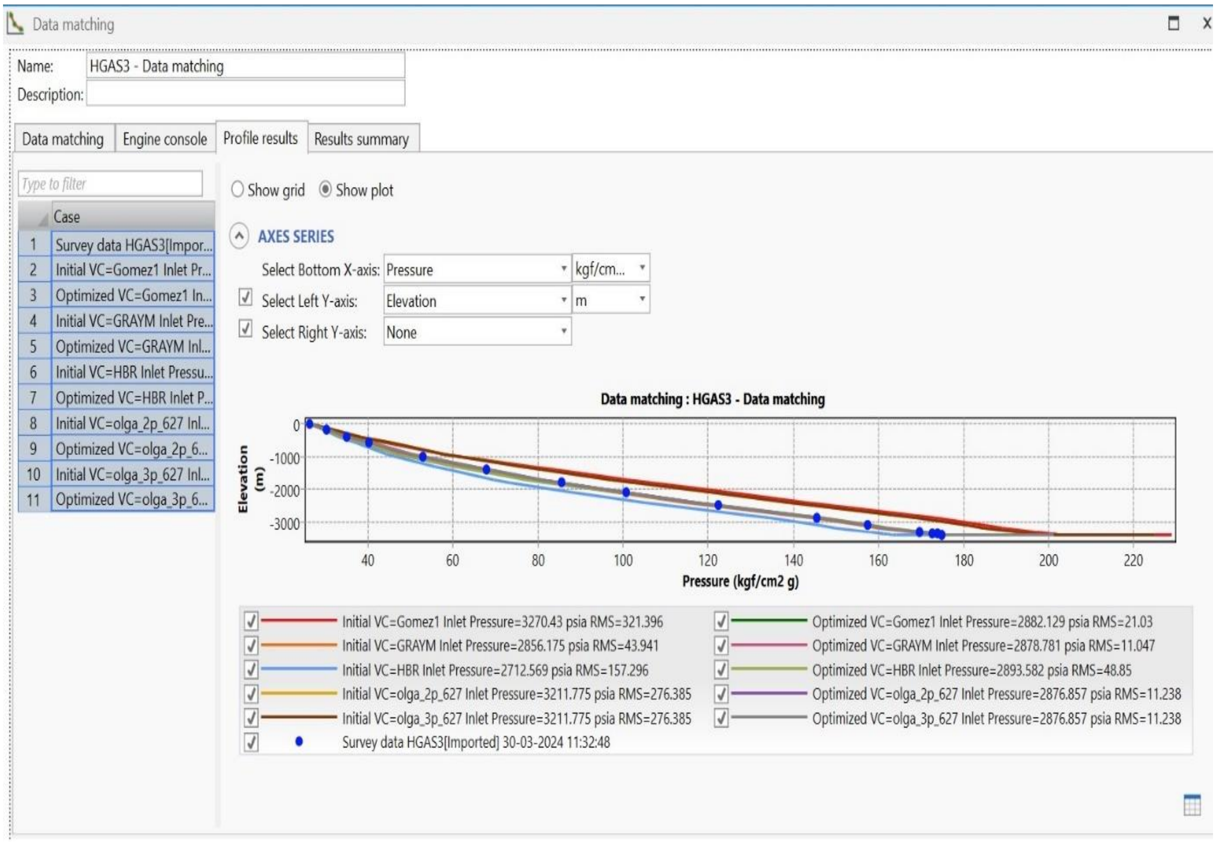
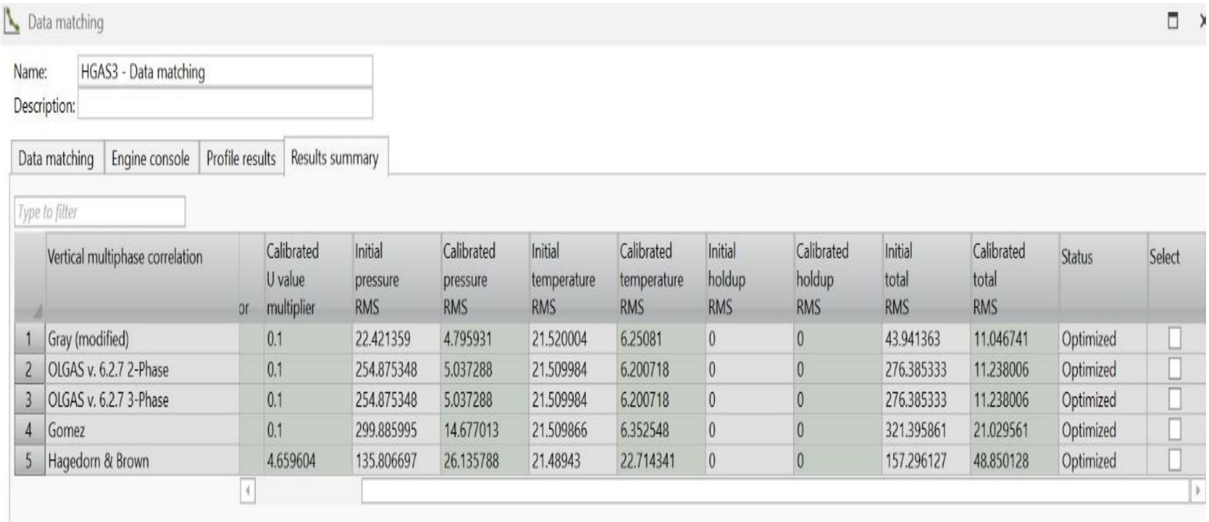


Figure III-15 : Well correlation matched graph.

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



	Vertical multiphase correlation	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	Status	Select
1	Gray (modified)	0.1	22.421359	4.795931	21.520004	6.25081	0	0	43.941363	11.046741	Optimized	
2	OLGAS v. 6.2.7 2-Phase	0.1	254.875348	5.037288	21.509984	6.200718	0	0	276.385333	11.238006	Optimized	
3	OLGAS v. 6.2.7 3-Phase	0.1	254.875348	5.037288	21.509984	6.200718	0	0	276.385333	11.238006	Optimized	
4	Gomez	0.1	299.885995	14.677013	21.509866	6.352548	0	0	321.395861	21.029561	Optimized	
5	Hagedorn & Brown	4.659604	135.806697	26.135788	21.48943	22.714341	0	0	157.296127	48.850128	Optimized	

Figure III-16 : RMS Results Obtained by Data Matching.

Table III-6 : RMS values for each well correlation

CORRELATION	RMS
Gray (modified)	11.04
OLGAS v. 6.2.7 3-Phase	11.23
OLGAS v. 6.2.7 2-Phase	11.23
Gomez	21.02
Hagedorn & Brown	48.85

OLGAS v. 6.2.7 3-Phase correlation is deemed suitable due to having the lowest RMS and being highly beneficial in instances of water-cut.

III.2.9 Well performance:

Well performance assessment involved the integration of build-up and gauging data derived from the HGAS3well into computational software for the determination of the system's operational state. The pertinent parameters included:

- Borehole temperature (T): 118°C
- Borehole pressure: 186 kg/cm²
- Average oil density, as per API gravity: 43.11
- Gas density (dg): 0.853
- Water density (dw): 1.2748
- Dissolution Gas-Oil Ratio (Rs): 196 m³/m³
- Bubble point pressure (Pb): 81 kg/cm²
- 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 196.

III.2.10 Latest well test (BU) matching:

Furthermore, the alignment with the latest well test (BU) involved the consideration of fundamental data, including:

❖ Outflow parameters:

- Oil flow rate (Qoil): 4.33 m³/h
- Head pressure: 32.3 kg/cm²
- Head temperature: 45.78°C

- Utilization of the correlation OLGAS v. 6.2.7 3-Phase for vertical flow.
- Tubing outside diameter: 4'1/2 from 0 to 3147 m (Inner Diameter (ID) = 3.92 inches, wall thickness = 0.29 inches)
- Measured Depth (MD): 3469 m
- Choke diameter: 9 mm

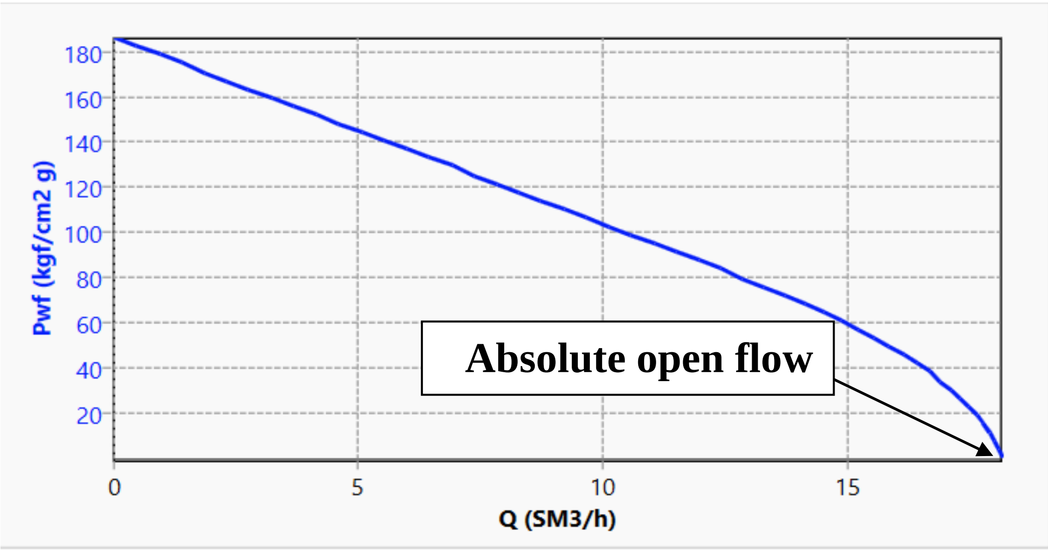


Figure III-17 : IPR Curve Of Well.

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).

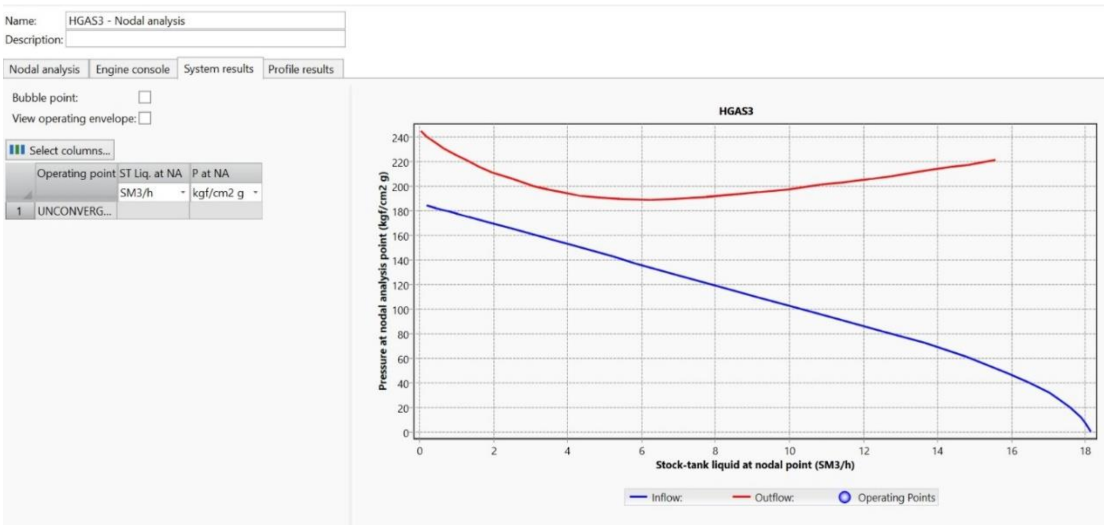


Figure III-18 : Well curve before optimization.

The well is non-productive due to its inability to generate sufficient fluid flow. Pre-optimization 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 bottomhole 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.

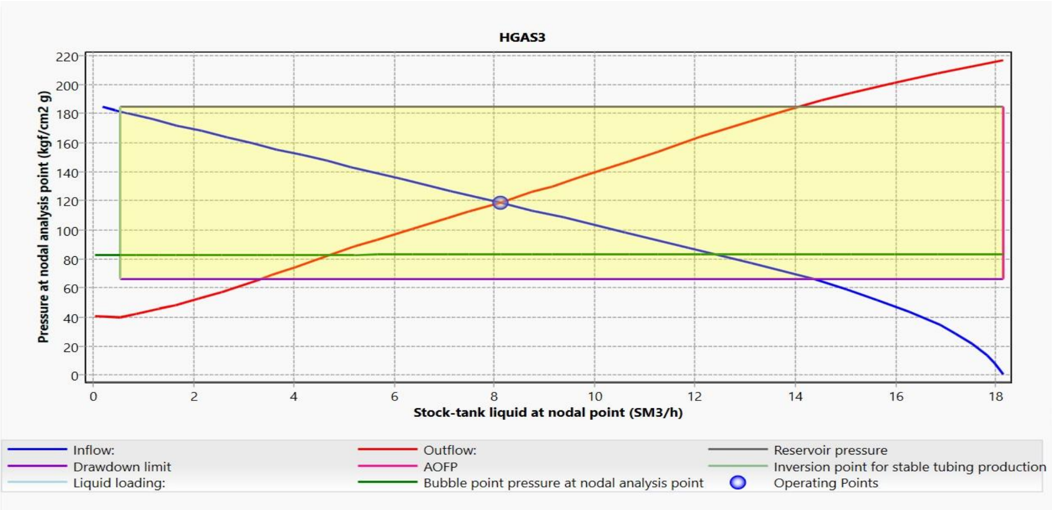


Figure III-19: Nodal Well Analysis.

III.2.11 Gas-lift performance of HGAS3 well:

In our study, the completion consists of a 4½-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 HGAS3.

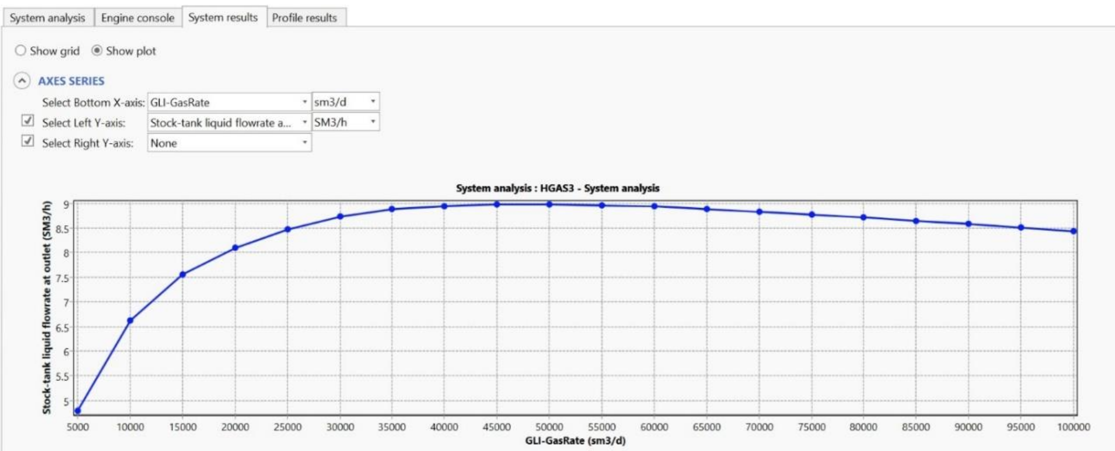


Figure III-20: Gas-lift performance curve.

From this curve, we can see that the optimum gas injection rate is 20000 sm3/d, which corresponds to an oil flow rate of 8.1m3/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.

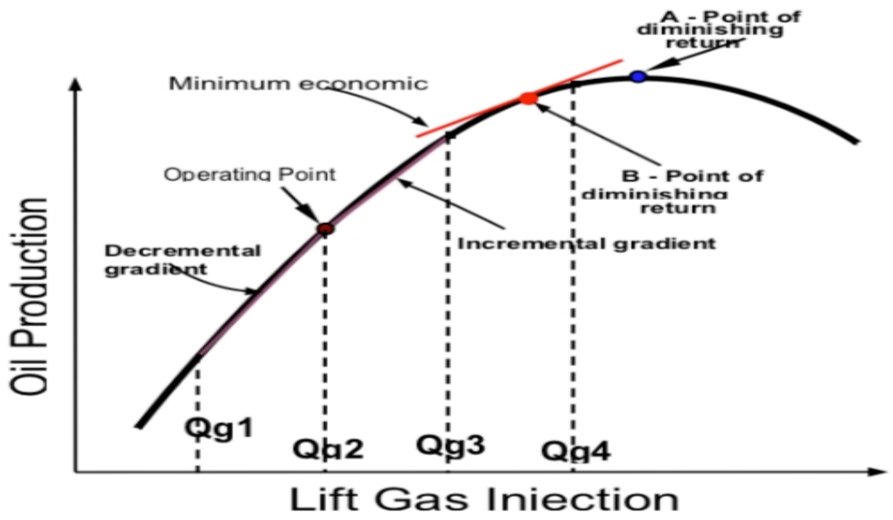


Figure III-21: Injection rate optimization [18]

Optimum flow

	ST Oil at out...	GLI-GasRate	P at WH
	SM3/h	sm3/d	kgf/cm2 g
1		0	
2	6.629099	10000.09	19.40566
3	8.111448	19999.91	23.3792
4	8.730435	29998.87	26.48597
5	8.950352	40000.38	29.54697
6	8.981454	49999.06	32.54351
7	8.935152	60000.57	35.29966
8	8.838403	69999.24	37.87764
9	8.716555	80000.75	40.34061
10	8.582688	89999.43	42.72299
11	8.442171	100000.9	45.04478

Figure III-22 : Determining the optimum gas lift flow rate.

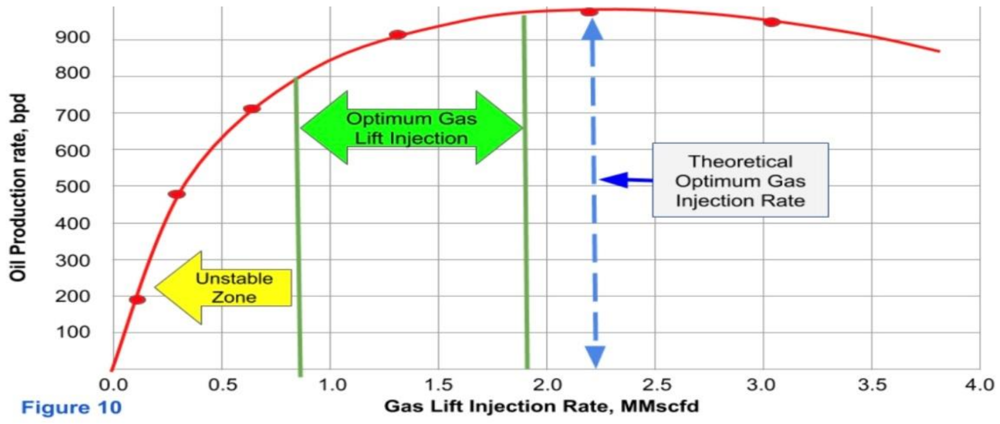


Figure III-23 : Gas lift performance: gas lift injection vs. oil production.

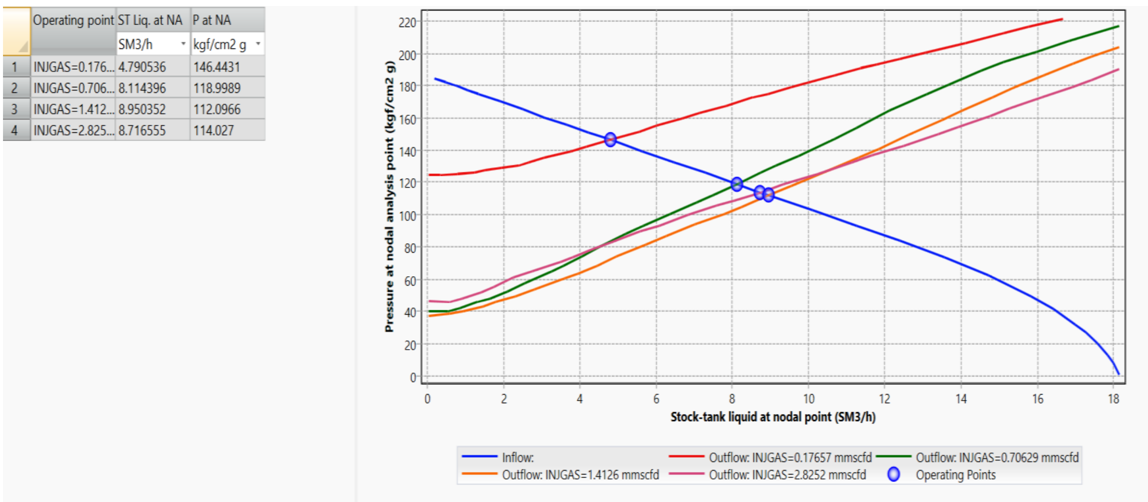


Figure III-24 : Max gas lift injection effect pressure at node vs. liquid rate.

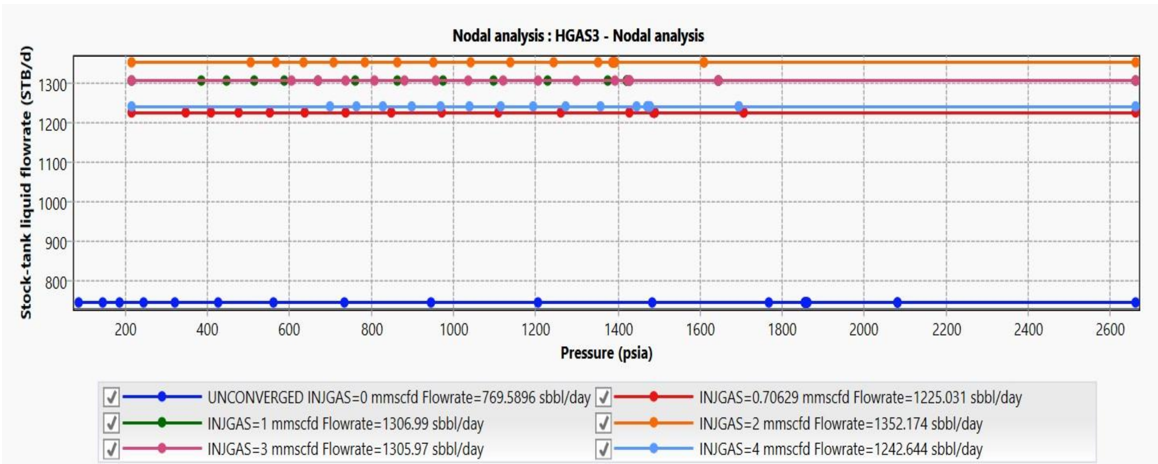


Figure III-25 : Max gas lift injection effect liquid rate vs. pressure.

III.2.12 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 HGAS3.

This table illustrates the comparison of oil flow rates before and after optimization for Well HGAS3, along with the determined optimum flow rate.

Table III-7 : Comparison of results before and after optimization.

WELL	Q Oil (Sm3/j)		Q Gas
	Before optimization	After optimization	Optimum Sm3/d
HGAS3	0	194.64	20000

The oil flow rate before optimization stood at 0 (Sm3/d), escalating significantly to194.64 (Sm3/d) following optimization, the subsequent determination of the optimum flow rate post-optimization yielded 20000 (Sm3/d).

III.2.12.1 Results and discussion:

Within the discourse of this Section, attention is directed towards the HGAS3 well situated within a depleted reservoir, characterized by a current pressure of approximately 186 kg/cm2. A gas-lift flow rate of 20000 Sm3/d is deemed crucial. Consequently, Perform gas lift optimization gauging to confirm optimum oil flow, leveraging the outcomes derived from PIPESIM modeling.

III.2.13 Parameters influencing gas lift:

Furthermore, this section delves into the influential parameters governing gas lift operations. It is elucidated that the optimal production of gas-lift-equipped wells may be subject to the fluctuations of various parameters over time, often resulting in disturbances and subsequent declines in production. Notably, parameters such as concentric outer diameter, choke characteristics, and bearing pressure are identified as particularly susceptible factors warranting meticulous consideration.

The optimal production of a well equipped with gas-lift is likely to be affected by certain numbers of parameters that will change over time.

Parameters that will change over time, these changes will cause disturbances in production and generally a drop in production. Among the most sensitive parameters are:

- Tubing inter diameter.
- Choke.
- Reservoir pressure.

III.2.13.1 Influence of the inside diameter of the tubing:

In our case, we will vary the inside diameter of tubing and record the liquid flow rate corresponding to each diameter in order to assess the influence of the change in diameter on production.

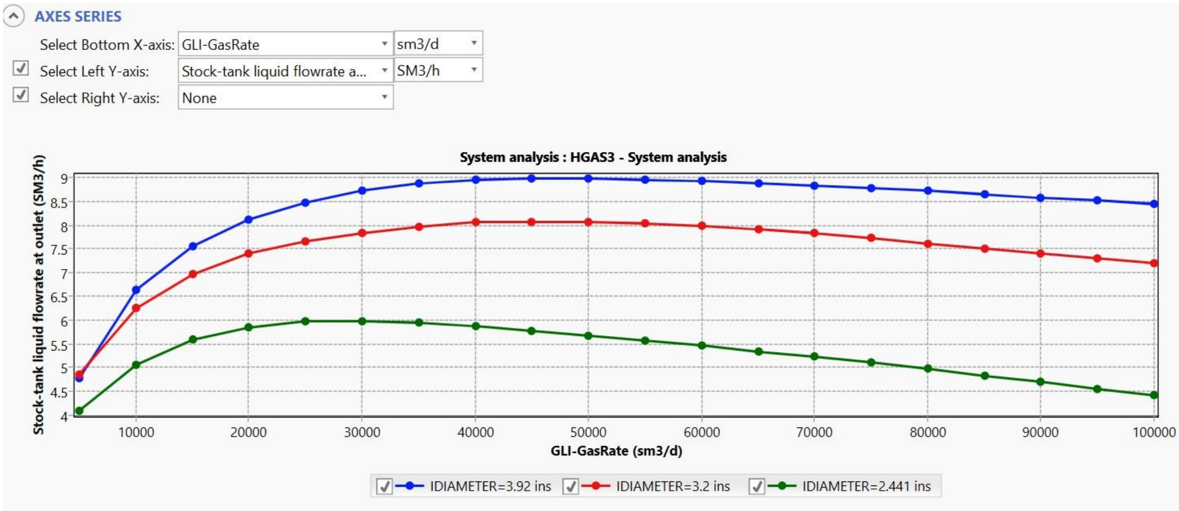


Figure III-26 : Evolution of the tubing inside diameters on Production.

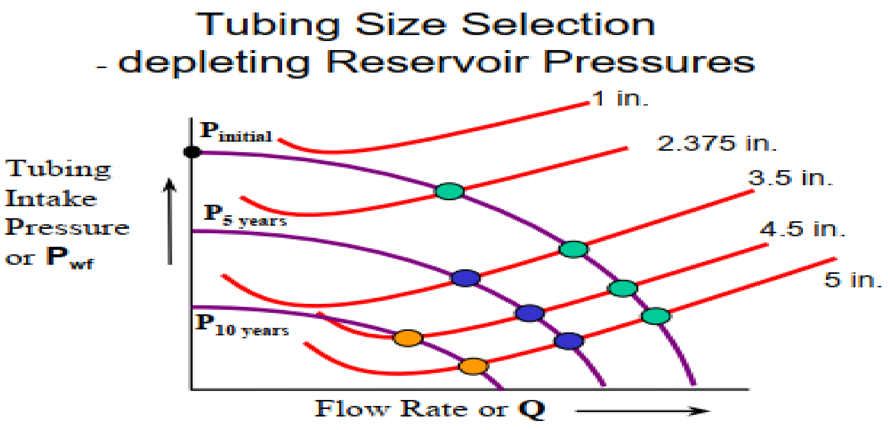


Figure III-27: Tubing size selection vs. depleting reservoir pressures. [19]

- Tubing too small will restrict the production rate because of excessive friction loss.
- Tubing too large will cause a well to load up with liquids and die.
- A common problem that occurs in completion large capacity well is to install very large tubing to be safe, which often results in a decreased flowing life for the wells are reservoir pressure declines and the wells begin to load .

Table III-8 : Variation results for HGAS3 tubing inside diameter.

Inside diameter of tubing (inch)	Optimum Qo Sm3/d	Qg Sm3/d
2.441	139.2	20000
3.2	177.6	20000
3.92	194.4	20000

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.

III.2.13.2 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 ΔP (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.

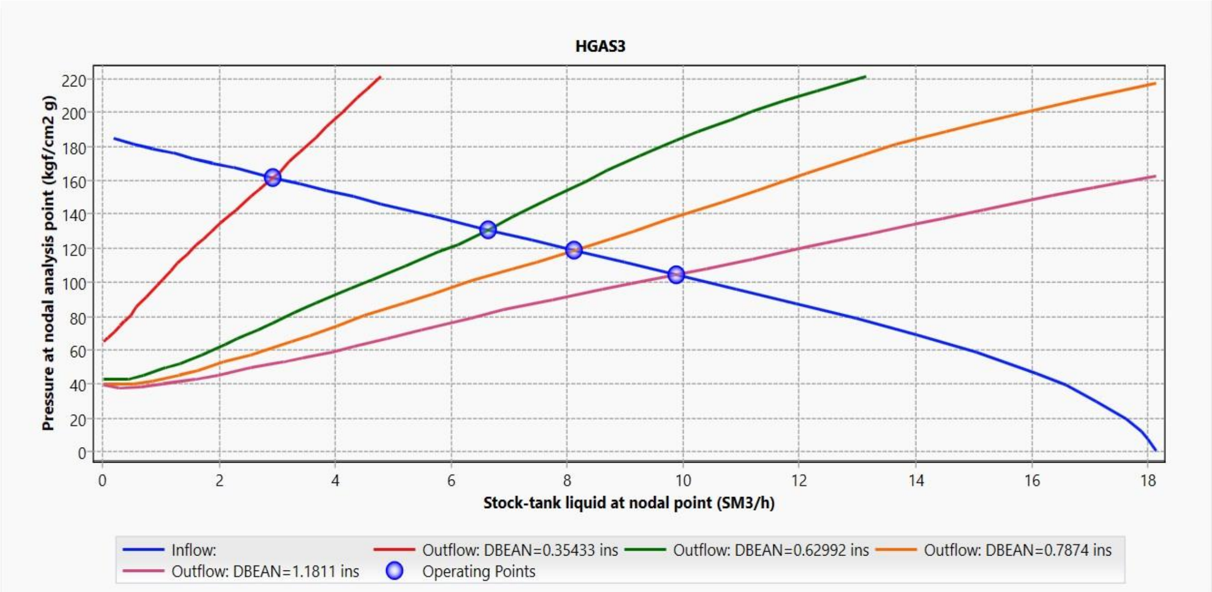


Figure III-28: Choke diameter influence.

This figure presents HGAS3 well bottomhole nodal analysis plot of inflow and outflow curves for different bean sizes. As the bean size is increased successively from 9 mm to 30, the outflow curves shift repeatedly to the right, hence the point of intersection (operating point) also shift to the right. The most suitable bean size for our case is 20 mm.

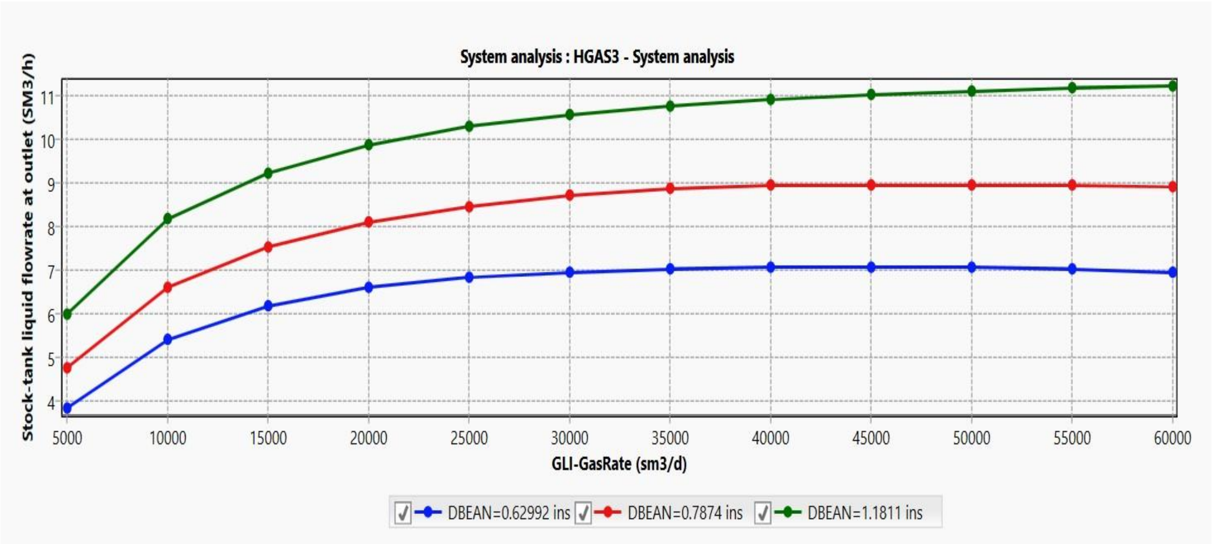


Figure III-29: Evolution of choke diameters on Production.

III.2.14 Performance optimization on studied well:

III.2.14.1 Used data:

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:

Table III-9 : Data used

DATA	HGAS3
Reservoir Pressure(kg/cm2)	186
Oil API	43.11
Gas Specific Gravity	0.853
Water Gravity	1.2748
Rs(Sm3/Sm3)	196
Tubing	4”1/2
MD(m)	3469
Completion	LCP

❖ **Gas injection parameters:**

- Surface injection pressure : 1792 psi.
- Surface injection temperature: 59 degf.
- Gas specific gravity: 0.712.

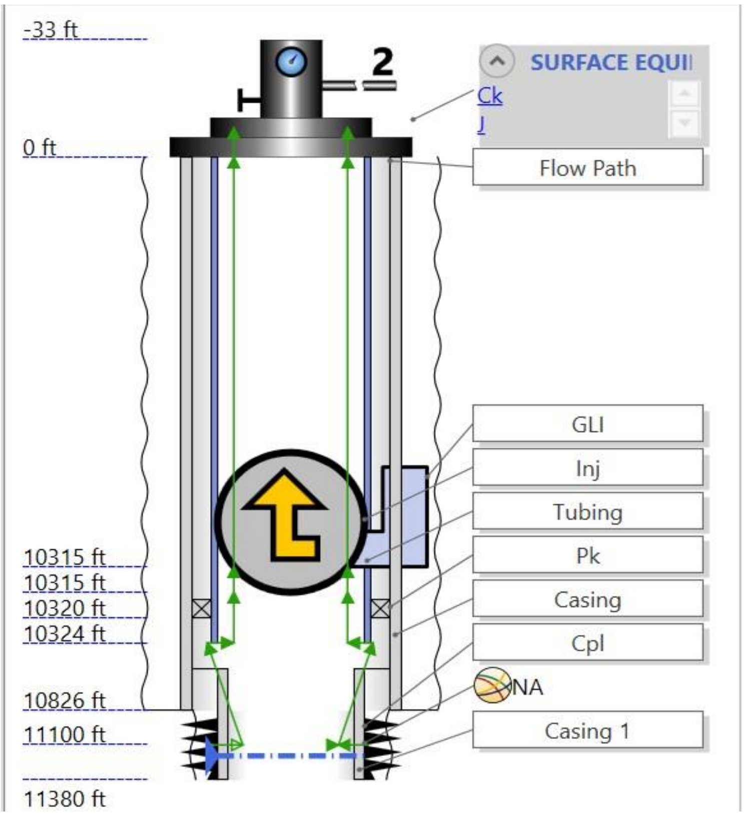


Figure III-30: Gas lift injection depth.

III.2.15 Overview of PROSPER software:

PROSPER is a well performance, design and optimization program which is part of the Integrated Production Modelling Toolkit (IPM). This tool is the industry standard well modelling with the major operators worldwide.

PROSPER is designed to allow the building of reliable and consistent well models, with the ability to address each aspect of well bore modelling; PVT (fluid characterization), VLP correlations (for calculation of flow-line and tubing pressure loss) and IPR (reservoir inflow).

PROSPER provides unique matching features, which tune PVT. Multiphase flow correlations and IPR to match measured field data, allowing a consistent well model to be built prior to use in prediction (sensitivities or artificial lift design). PROSPER enables detailed surface pipeline performance and design: Flow Regimes, pipeline stability, Slug Size and Frequency.

❖ **APPLICATIONS**:

- Design and optimize well completions including multi-lateral, multilayer and horizontal wells.
- Design and optimize tubing and pipeline sizes.
- Design, diagnose and optimize Gas lift, Hydraulic pumps and ESP wells.
- Generate lift curves for use in simulators.
- Calculate pressure losses in wells, flow lines and across chokes.
- Predict flowing temperatures in wells and pipelines.
- Monitor well performance to rapidly identify wells requiring remedial action calculate total skin and determine breakdown (damage, deviation or partial penetration).
- Unique black oil model for retrograde condensate fluids, accounting for liquid dropout in the wellbore allocate production between wells.

❖ **Disclaimer:**

Prosper mainly simulates the well without network consideration, thus giving us results maybe higher

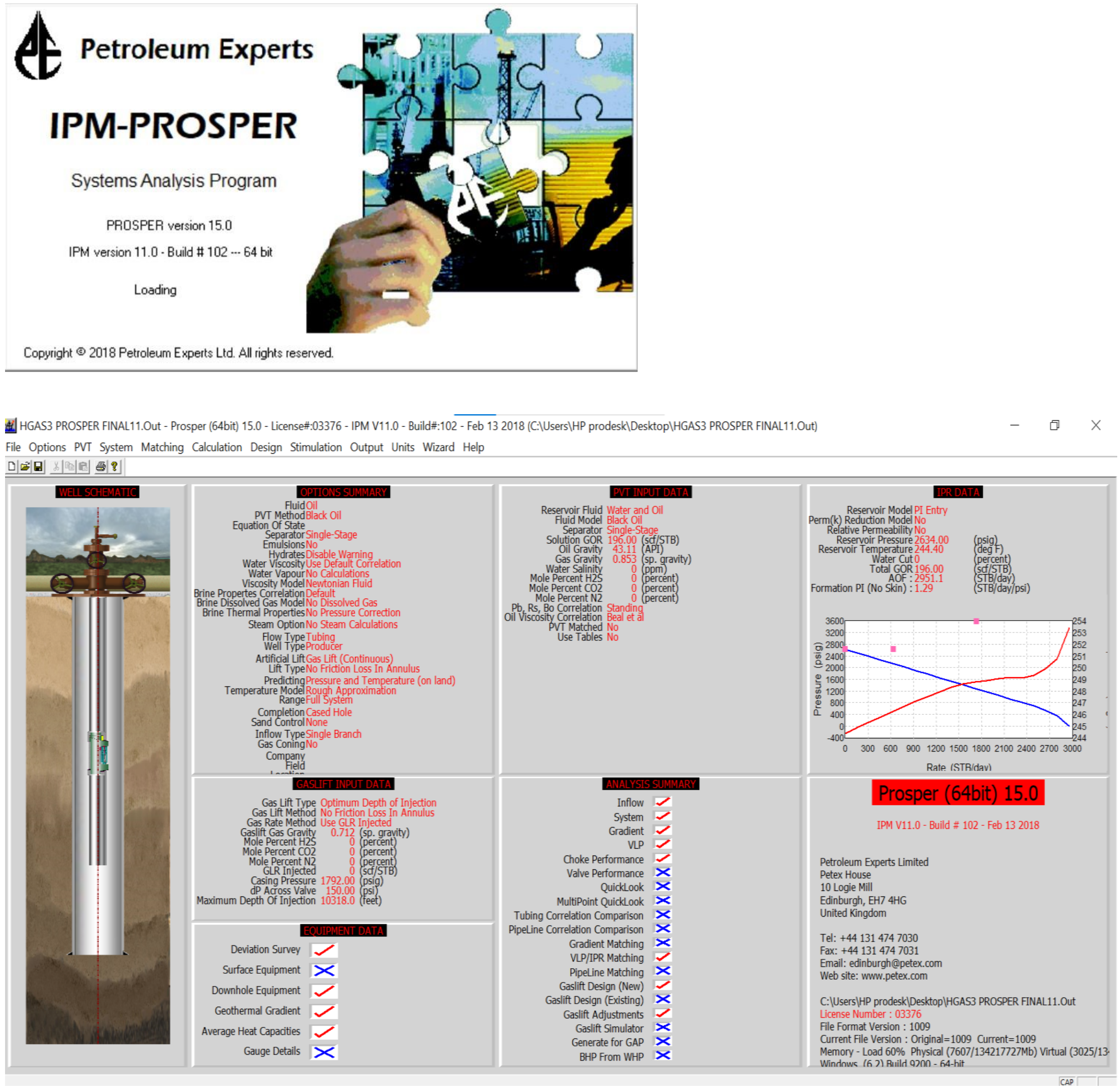


Figure III-31: PROSPER interface with the well's data.

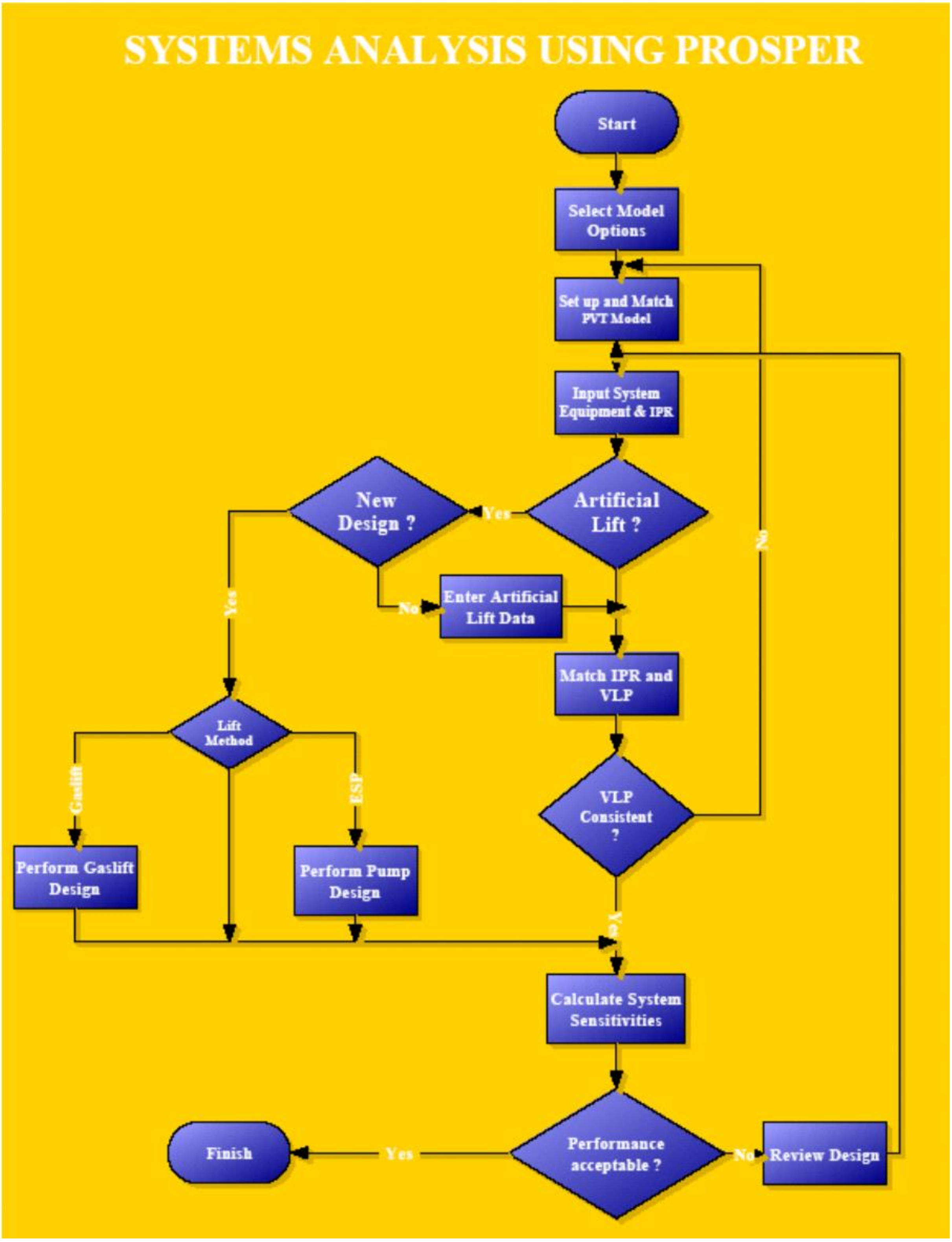


Figure III-32: System analysis using PROSPER.

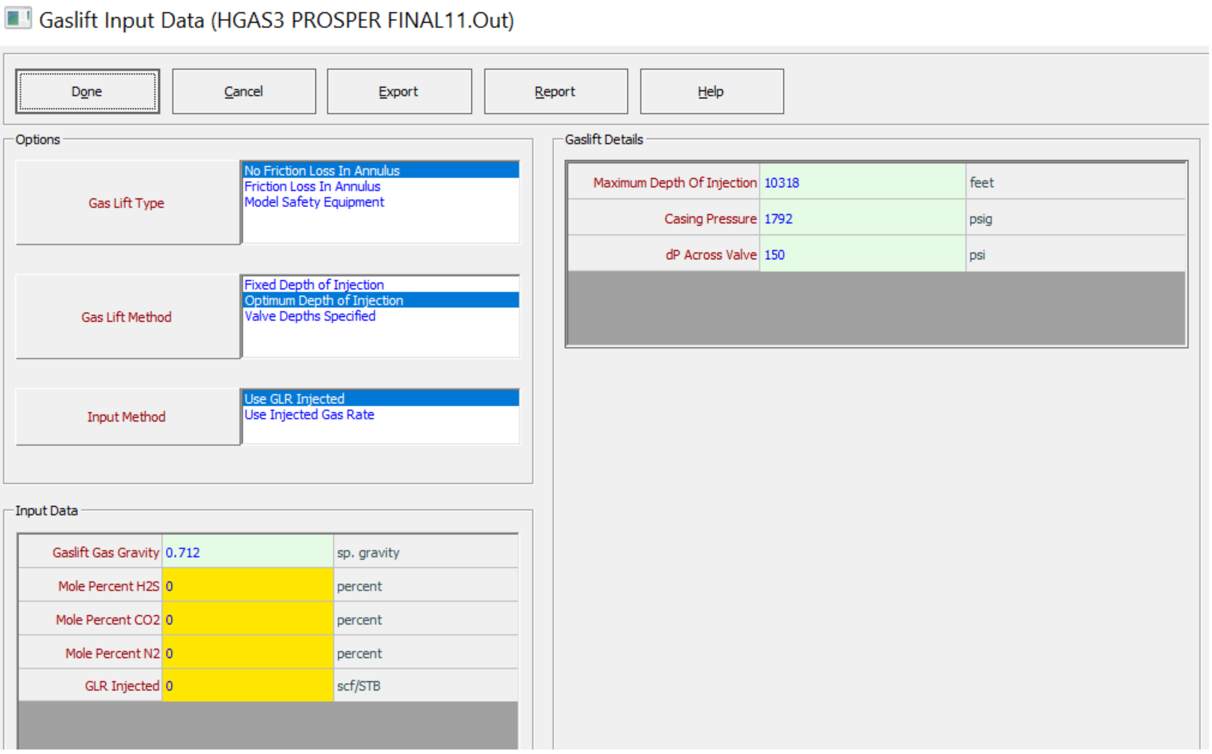


Figure III-33: HGAS3 gas lift input data.

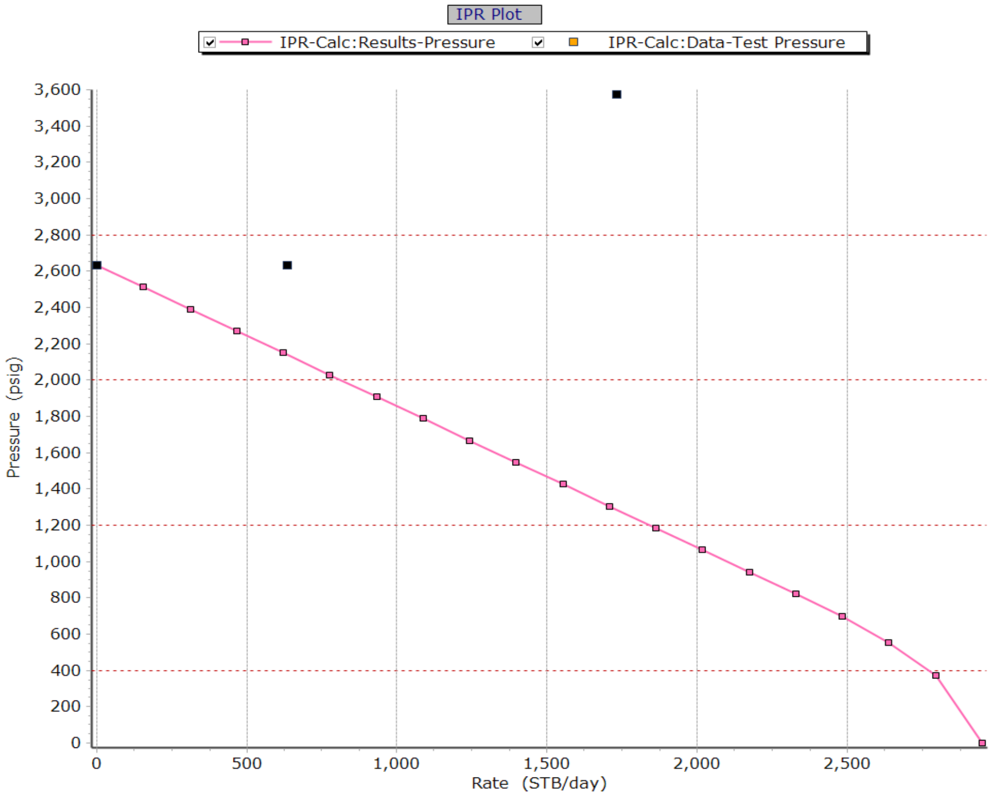


Figure III-34: Inflow Performance Curve plot.

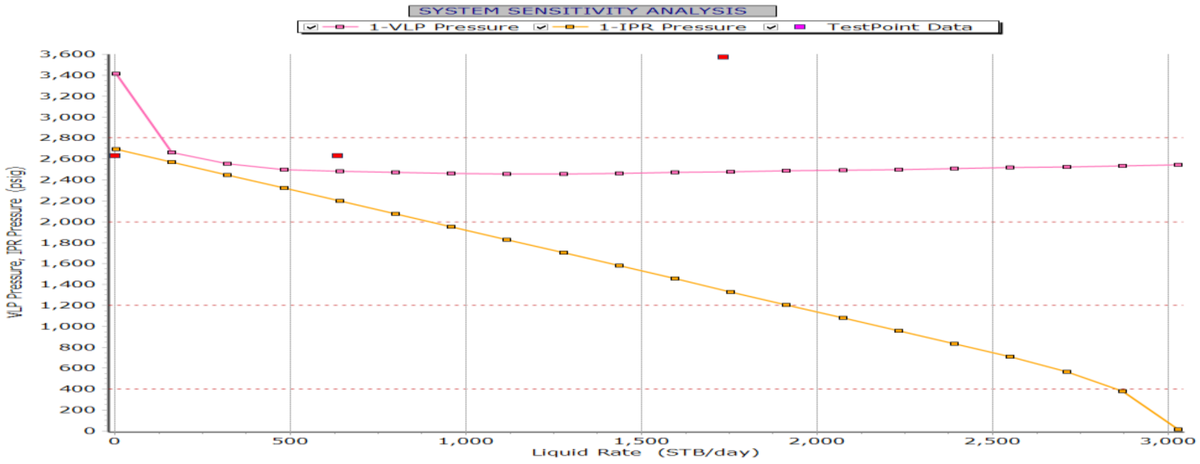


Figure III-35 : Well curve before optimization.

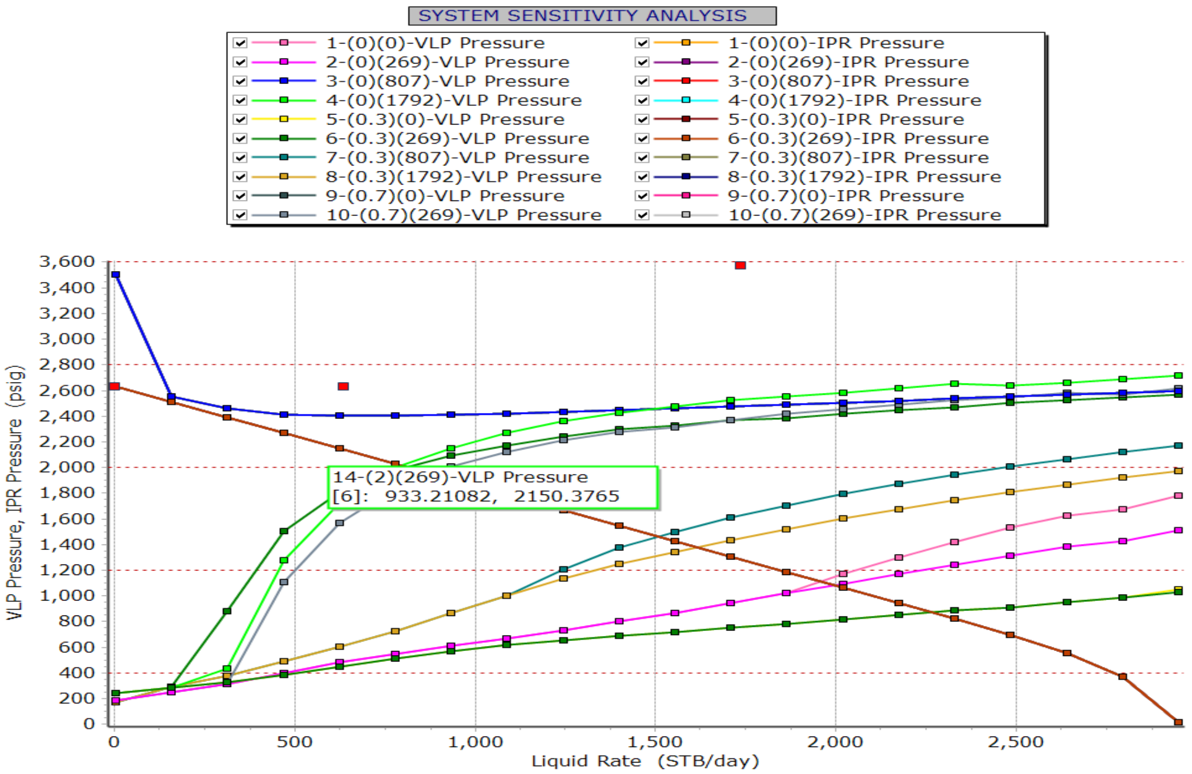


Figure III-36: Nodal well analysis with multiple gas injection rates and casing pressure case 14.

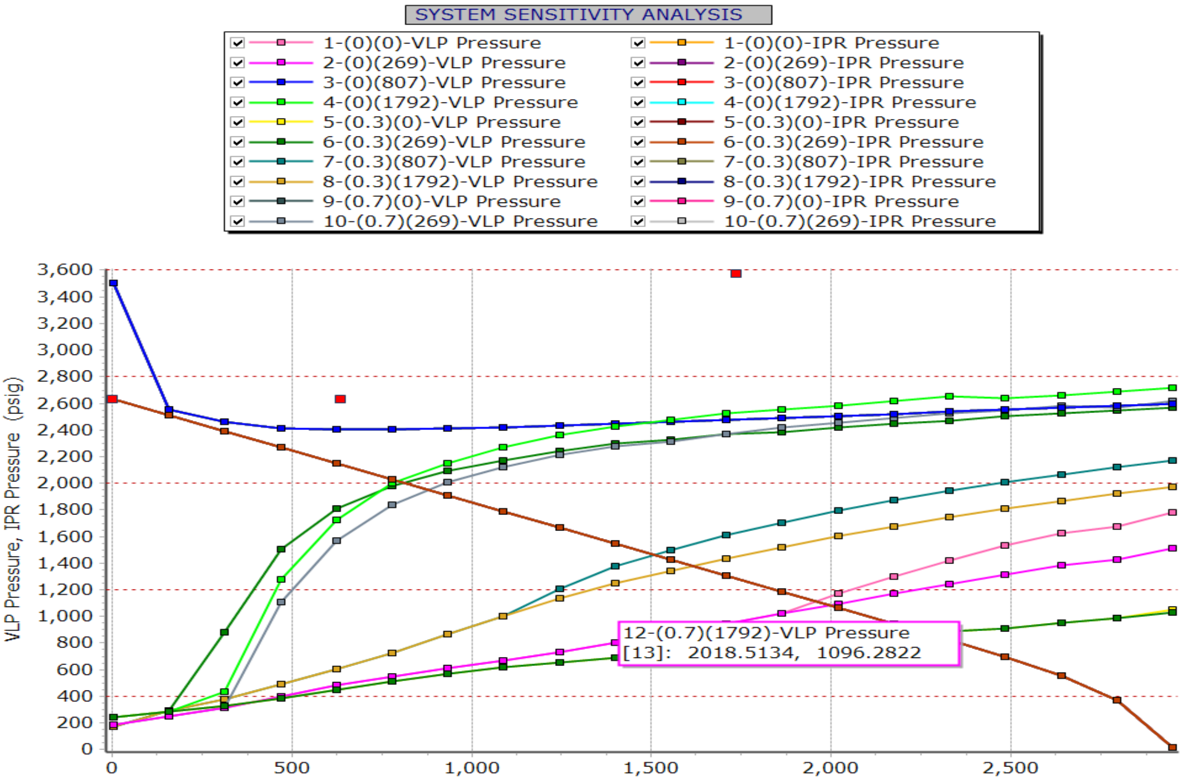


Figure III-37: Nodal well analysis with multiple gas injection rates and casing pressure case 12.

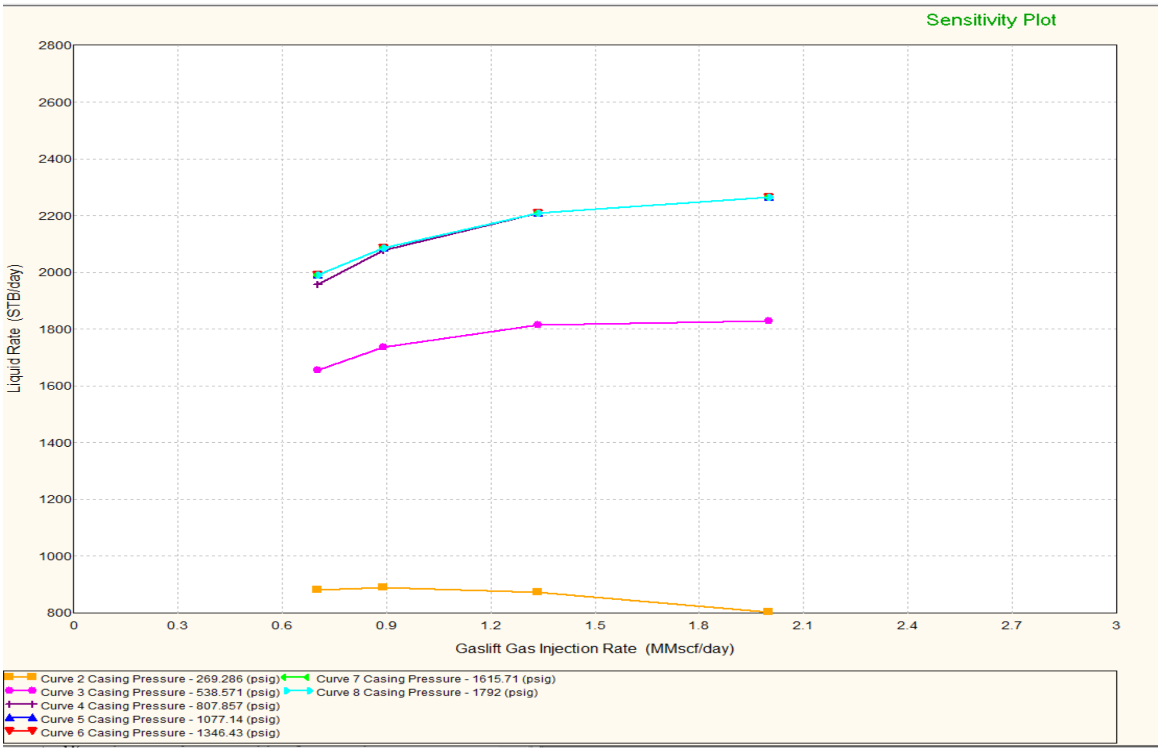


Figure III-38: Casing pressure vs. Liquid rate.

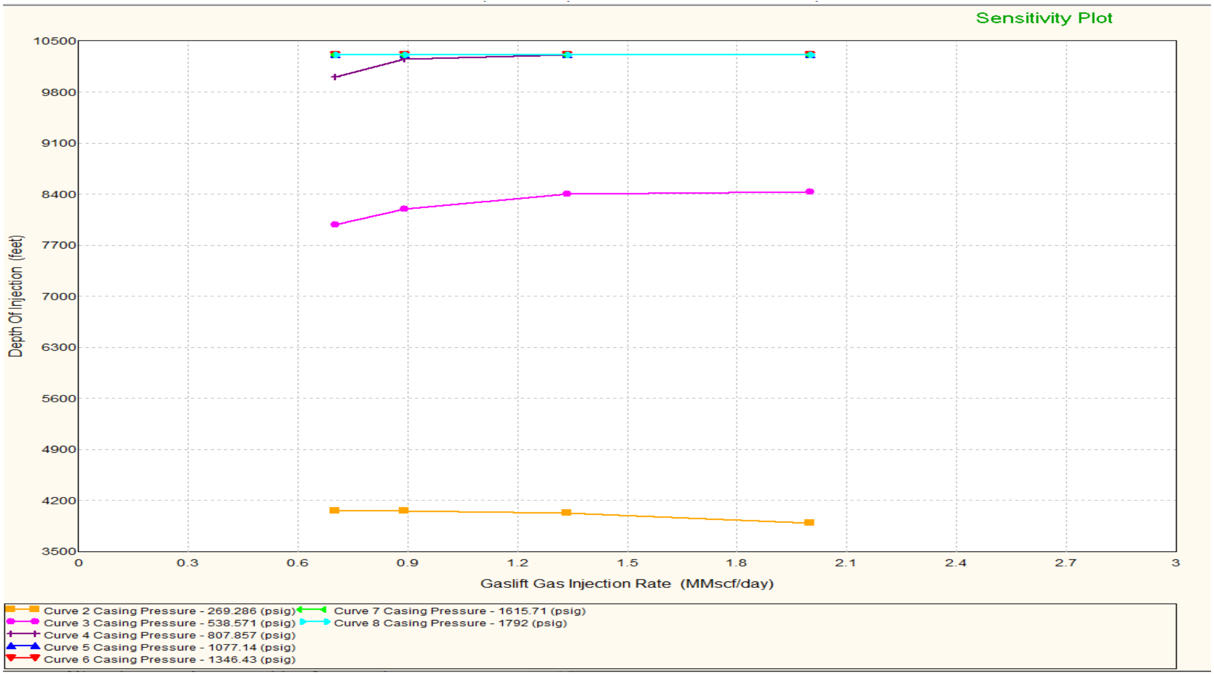


Figure III-39: Casing pressure vs. injection depth.

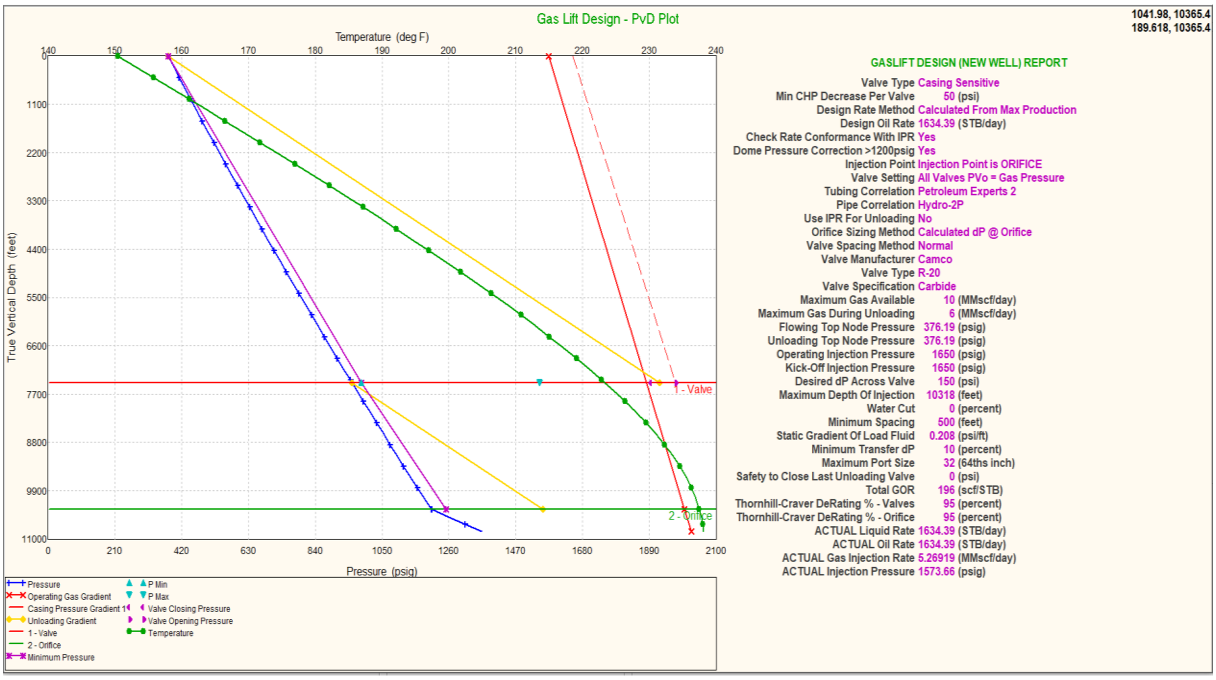


Figure III-40: Proposed gas lift design.

Conclusion

And

Recommandations

Conclusion

The main aim of this work is to optimize the performance of non-eruptive wells through gas injection by assessing the impact of reservoir depletion on Hassi Messaoud field, taking into account the gas lift activation system for fluid flow from reservoir to surface with optimal well parameters (oil and gas flow rate).

Gas lift is the most widely used activation method in Hassi Messaoud (HMD) field. This technique involves injecting gas at the bottom of the production tubing to reduce fluid density.

In our study, we examined several parameters influencing the optimization of gas lift. We utilized the PIPESIM and PROSPER software to enhance the performance of HGAS3 well. The parameters studied included the quantity of gas injected, the injection depth, and the inner diameter of the tubing.

The following conclusions can be highlighted:

- The optimal gas injection rate:
  - For HGAS3: The optimal gas rate (Qg) is 20000 sm^3/d, corresponding to an oil rate (Qoil) of 194.64 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 10318 feet, and choke diameter=20 mm.
- The performance of the HGAS3 well is enhanced by a significant gain in oil flow and a permanent production regime with optimum gas lift flow.
- The optimization of gas-lift wells by determining a well operating point and injecting an optimum gas flow corresponding to a maximum oil flow.
- The flow rate of a gas-lift well depends on the diameter of the casing used.
- Optimizing the gas injection rate minimizes the total pressure losses (both gravitational and frictional).

Recommendation

- Daily monitoring of gas injection flow and pressure to ensure smooth operation of gas-lift wells.
- Implement real-time data acquisition systems to continuously monitor well performance and dynamically adjust nodal analysis models for immediate optimization.
- Invest in high-quality sensors and data logging equipment to ensure the accuracy and reliability of input data for nodal analysis. Regular calibration and maintenance of these instruments are crucial.
- Schedule periodic well tests to better analyze reservoir behavior.
- Appropriate injection scheme for pressure maintenance to limit decline in reservoir pressure.

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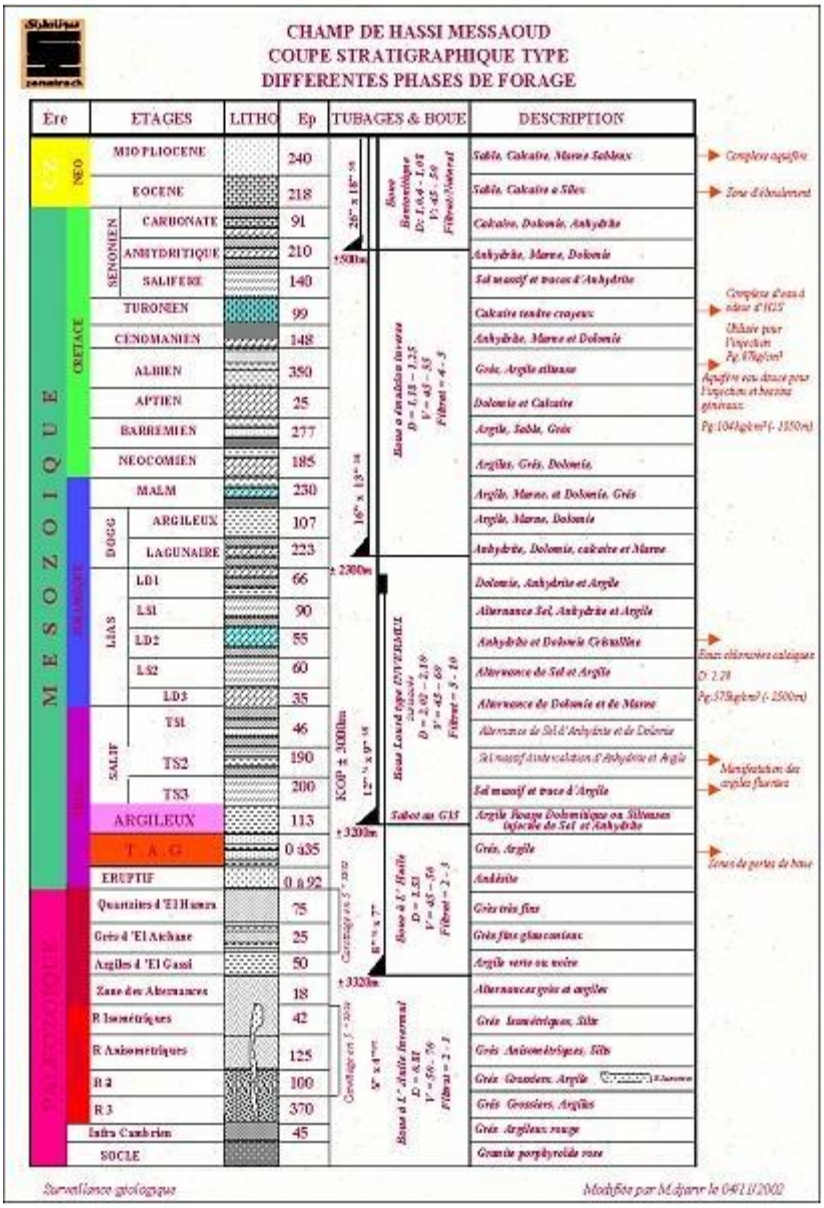
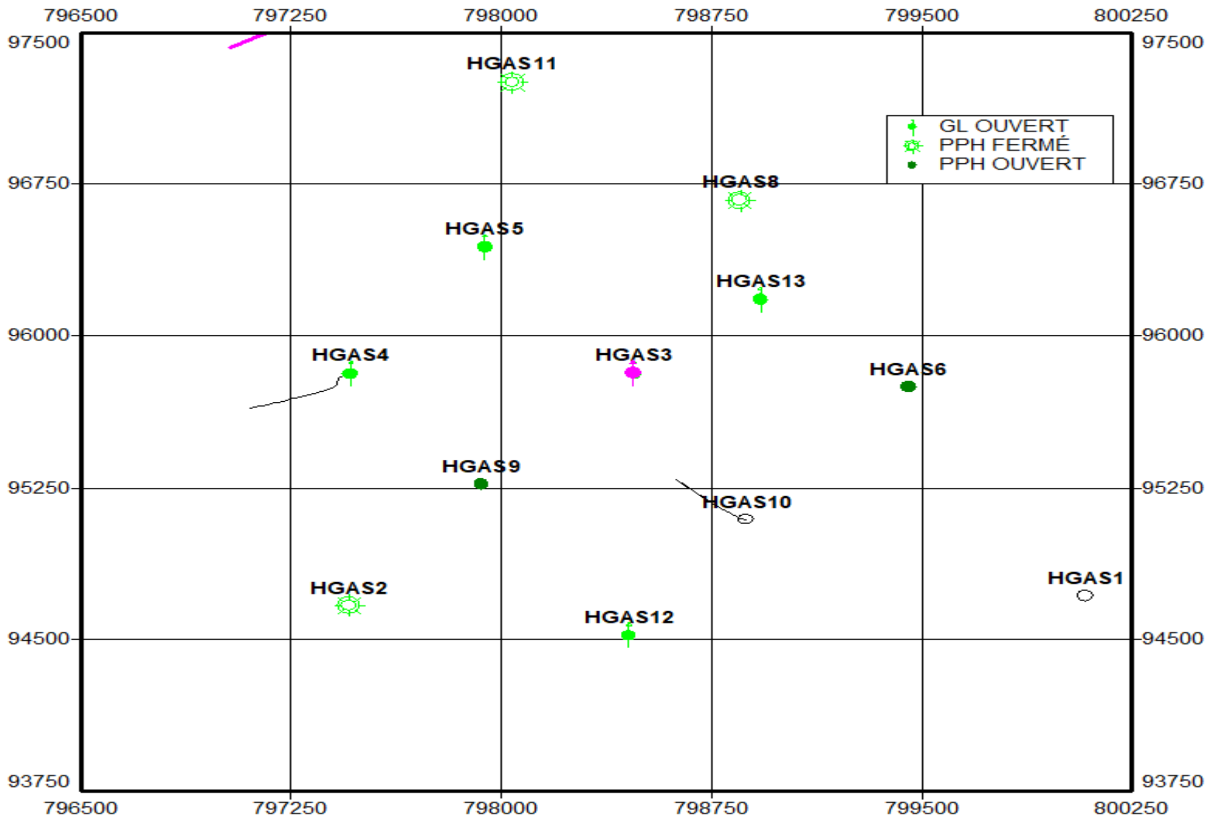
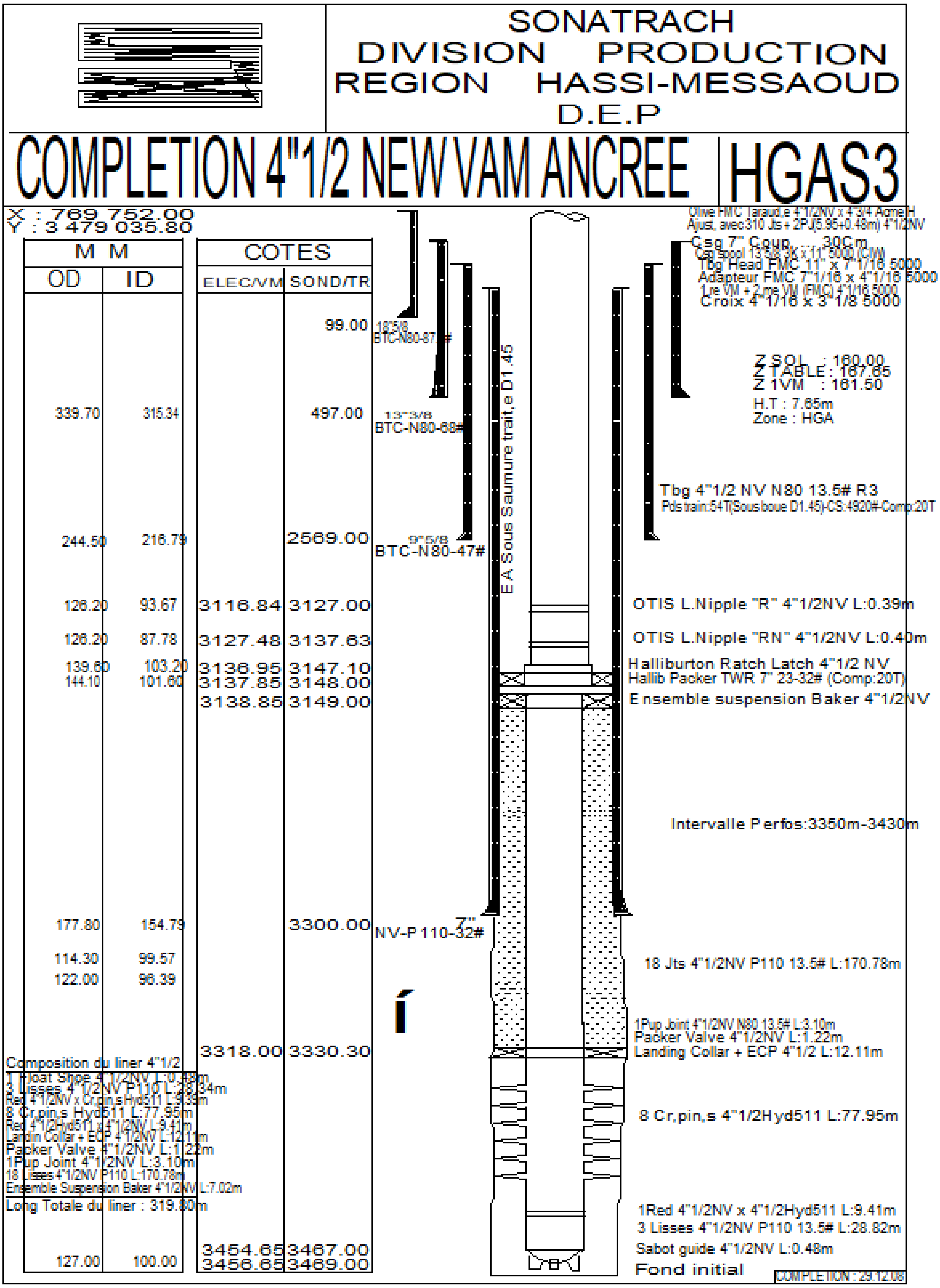
ANNEX



Stratigraphic section of Hassi Messaoud field.



HGAS3's adjoining wells.



HGAS3 Well Data Sheet.