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-THEME-

Hydrate Mitigation and Flare Reduction Using Intermittent Gas Lift

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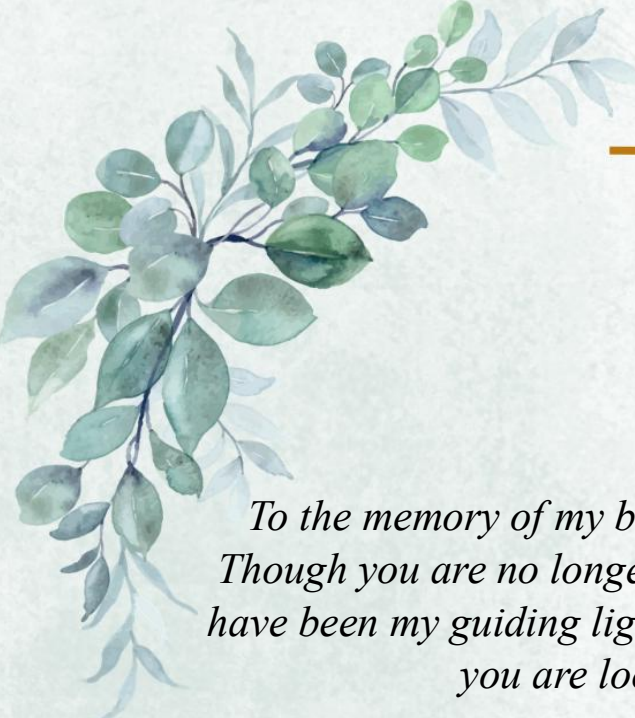
First and foremost, we praise Almighty Allah for granting us the strength and perseverance to successfully complete this research work.

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DEDICATION

To the memory of my beloved father, who passed away last year. Though you are no longer with us, your spirit, vision, and blessings have been my guiding light through every step of this journey. I hope you are looking down with pride today.

To my wonderful mother, the pillar of my strength and my ultimate source of inspiration. Thank you for your unconditional love, endless prayers, and sacrifices. Honestly, I could never have done this without you.

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To everyone who was close to me, especially my dedicated partners in this work; thank you for sharing this journey with me.

KESSAL abdellatif





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All praise and thanks are due to Allah for granting me strength, patience, guidance in the completion of this work.

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ملخص البحث

يُعد تحسين عملية الرفع بالغاز (Gas lift) تحديًا بالغ الأهمية في هندسة البترول، لا سيما فيما يتعلق بتخفيف تكون الهيدرات وتقليل معدلات حقن الغاز المفرطة. تبحث هذه الدراسة في الانتقال من الرفع المستمر بالغاز (CGL) إلى الرفع المتقطع بالغاز (IGL) كاستراتيجية لتخفيف تكون الهيدرات وتعزيز أداء الإنتاج في البئر Z09 بحقل TFT. تم إنشاء منحنيات استقرار الهيدرات باستخدام برنامج PVTP، بينما كشف تحليل بيانات الحقل الحالية لعمليات الرفع المستمر (CGL) عن ظروف تشغيل تبلغ 28.32 بار و 6.02 درجة مئوية. أكد هذا التحليل أن ظروف التشغيل الحالية لـ CGL تقع ضمن منطقة استقرار الهيدرات، مما يشير إلى خطر كبير بحدوث انسداد في اتجاه مجرى صمام الحقن. ولتقييم إمكانية التخفيف باستخدام الرفع المتقطع (IGL)، تم إجراء تحليل لتأثير جول-تومسون (Joule–Thomson) لتقدير معايير التشغيل. أشارت الحسابات إلى تحول في نقطة التشغيل إلى 58 بار و 19.03 درجة مئوية، مما أدى إلى إعادة تموضع نقطة التشغيل بشكل فعال داخل المنطقة الخالية من الهيدرات. أظهرت المحاكاة الرقمية التي تم إجراؤها باستخدام برنامج PROSPER أن الانتقال إلى الرفع المتقطع (IGL) يعزز إنتاج النفط من 8.35 Sm³/يوم إلى حوالي 11.4 Sm³/يوم، مع تقليل معدل حقن الغاز في الوقت نفسه من 5521 Sm³/يوم إلى 1170.34 Sm³/يوم. تثبت هذه النتائج أن الرفع المتقطع بالغاز هو حل تقني قوي لضمان التدفق وتحسين الإنتاج، مما يساهم في تحسين الكفاءة التشغيلية وتقليل عمليات حرق الغاز السطحي.

الكلمات المفتاحية: الرفع بالغاز، تأثير جول-تومسون، تكون الهيدرات، الرفع المتقطع بالغاز (IGL)، تحسين الإنتاج، برنامج PROSPER.

Abstract

Gas lift optimization remains a critical challenge in petroleum engineering, particularly regarding the mitigation of hydrate formation and the minimization of excessive gas injection rates. This study investigates the transition from Continuous Gas Lift (CGL) to Intermittent Gas Lift (IGL) as a strategy to mitigate hydrate formation and enhance production performance in Well Z09 within the TFT field. Hydrate stability curves were generated using PVTP software, analysis of current field data for CGL operations revealed operating conditions of 28.32 bar and 6.02°C. This analysis confirmed that the current CGL operation resides within the hydrate stability region, indicating an elevated risk of blockage downstream of the injection choke. To evaluate the mitigation potential of IGL, a Joule–Thomson analysis was performed to estimate operating parameters. The calculations indicated an operating shift to 58 bar and 19.03°C, effectively repositioning the operating point within the hydrate-free zone. Numerical simulations performed in PROSPER demonstrated that the transition to IGL enhances oil production from 8.35 Sm³/day to approximately 11.4 Sm³/day, while simultaneously reducing the gas injection rate from 5521 Sm³/day to 1170.34 Sm³/day. These results demonstrate that

IGL is a robust technical solution for flow assurance and production optimization, contributing to improved operational efficiency and a reduction in surface gas flaring.

Keywords: hydrates, intermittent gas lift, Joule–Thomson, PROSPER, flare reduction.

Résumé

L'optimisation du "Gas Lift" demeure un défi critique en ingénierie pétrolière, notamment en ce qui concerne l'atténuation de la formation d'hydrates et la minimisation des taux d'injection de gaz excessifs. Cette étude examine la transition du "Gas Lift" continu (CGL) vers le "Gas Lift" intermittent (IGL) en tant que stratégie pour atténuer la formation d'hydrates et améliorer la performance de production du puits Z09 dans le champ TFT. Les courbes de stabilité des hydrates ont été générées à l'aide du logiciel PVTP, l'analyse des données de terrain actuelles pour les opérations en CGL a révélé des conditions de fonctionnement de 28,32 bar et 6,02°C. Cette analyse a confirmé que l'exploitation actuelle en CGL se situe dans la région de stabilité des hydrates, indiquant un risque élevé de blocage en aval de la vanne d'injection. Pour évaluer le potentiel d'atténuation de l'IGL, une analyse de l'effet Joule–Thomson a été effectuée afin d'estimer les paramètres de fonctionnement. Les calculs ont indiqué un décalage du point de fonctionnement vers 58 bar et 19,03°C, repositionnant efficacement le point de fonctionnement dans la zone exempte d'hydrates. Les simulations numériques réalisées avec PROSPER ont démontré que la transition vers l'IGL améliore la production de pétrole, passant de 8,35 Sm³/jour à environ 11,4 Sm³/jour, tout en réduisant simultanément le taux d'injection de gaz de 5521 Sm³/jour à 1170,34 Sm³/jour. Ces résultats démontrent que l'IGL est une solution technique robuste pour l'assurance d'écoulement et l'optimisation de la production, contribuant ainsi à une meilleure efficacité opérationnelle et à une réduction du torchage de gaz en surface.

Mots-clés: Hydrates, Gas Lift Intermittent (IGL), Effet Joule-Thomson, PROSPER, Réduction du torchage

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ABBREVIATIONS LIST

Abbreviation	Meaning	Unit
Pre	Reservoir Pressure	bar
Pwf	Flowing Bottomhole Pressure	bar
GOR	Gas-Oil Ratio	Sm ³ /Sm ³
GLR	Gas Liquid Ratio	Sm ³ /Sm ³
WC	Water Cut	%
PI	Productivity Index	m ³ /day/bar
Gp	Pressure Gradient	bar/m
MD	Measured Depth	m
TVD	True Vertical Depth	m
PPO	Operating Production Pressure	bar
IPO	Operating Injection Pressure	bar
GL	Gas Lift	-
IGL	Intermittent Gas Lift	-
CGL	Continuous Gas Lift	-
GLI	Gas Lift Injection	-
CL	Chamber Lift	-
API	American Petroleum Institute	-
ESP	Electrical Submersible Pump	-
PCP	Progressive Cavity Pump	-
SPM	Side Pocket Mandrel	-
CCE	Constant Composition Expansion	-
IPR	Inflow Performance Relationship	-
VLP	Vertical Lift Performance	-
PVT	Pressure-Volume-Temperature	-
SG	Specific Gravity	-
THI	Thermodynamic Hydrate Inhibitors	-
LDHI	Low Dosage Hydrate Inhibitors	-
KHI	Kinetic Hydrate Inhibitors	-
AA	Anti-Agglomerants	-
MEG	Monoethylene Glycol	-

GENERAL INTRODUCTION



GENERAL INTRODUCTION

The Tin Fouye Tabankort (TFT) field, located in the north-west of the Illizi Basin, remains a critical component of Algeria's hydrocarbon production. Since its discovery in 1967, the field has been a vital energy asset; however, as the field matures, maintaining production levels has become increasingly complex. To sustain output in wells where natural pressure has declined, artificial lift methods—particularly Continuous Gas Lift (CGL)—are widely employed.

While CGL is effective for increasing production, it is often hindered by significant flow assurance challenges. A primary concern is the formation of hydrates within gas injection lines. This issue is frequently triggered by the Joule–Thomson effect, where the sudden pressure drop across injection chokes causes a sharp decline in temperature, creating conditions conducive to hydrate crystallization. In the specific case of Well Z09, operational data indicates that current CGL practices lead to a pressure-temperature state—approximately 28.32 bar and 6.02°C—that falls squarely within the hydrate stability region, posing a persistent risk of flow blockage and operational disruption.

To address these limitations, this study evaluates the implementation of Intermittent Gas Lift (IGL) as a robust alternative. By transitioning from continuous to intermittent gas injection, the study aims to eliminate the persistent pressure drops that drive hydrate formation, thereby improving both well integrity and production efficiency. Through numerical simulations performed in PROSPER, this research demonstrates that IGL can effectively shift the well's operating parameters into the hydrate-free zone, enhancing oil recovery from 8.35 Sm³/day to 11.4 Sm³/day, while simultaneously reducing gas consumption and minimizing gas flaring.

The study is divided into four chapters:

- **Chapter 1:** *A presentation of the TFT field:* Presents the TFT field, including its geographical location, reservoir description, and main deposits.
- **Chapter 2:** *Overview of well activation:* Reviews well activation methods, focusing on gas lift principles, parameters, and flow performance.
- **Chapter 3:** *hydrate formation issues:* Discusses hydrate formation, its mechanisms, influencing factors, risks, and prevention methods.
- **Chapter 4:** *practical part:* This chapter presents the practical analysis of Well Z09, including hydrate-curve generation, CGL hydrate-risk evaluation, Joule–Thomson analysis, and IGL optimization using PROSPER.



CHAPTER I

PRESENTATION OF THE TFT FIELD



Chapter I : Presetntaion of the TFT field

I.1 Introduction

An oil field generally consists of gas, oil and water. These three fluids are not necessarily present at the same time, as there are oil and gas reservoirs and gas reservoirs without oil, but water is a permanent component of the reservoir, with varying levels of salts. Tin Fouyé Tabankort (TFT) is part of the production division of the National Company for the Transport and Marketing of Hydrocarbons (SONATRACH). It is responsible for oil and gas production in the various fields located in the TFT region, The principle The TFT regional production department was created in **1976** as part of the reorganization of the former In Aménas sector[6].

I.2 Presentation of the TFT region

The TFT region is part of the production division of National Company for the Transport and Marketing of Hydrocarbons (SONATRACH), and in this section we present the most important information about the TFT (geographical location and representation of the region's deposits and the regional management of the TFT region, production history).

I.2.1 Geographical location

The Tin Fouyé Tabankort (TFT) region is located in the northwestern part of the Illizi Basin, more precisely 284 km north of In-Amenas, 500 km southeast of Hassi Messaoud on National Road N°3, 1300 km from Algiers, and is administratively part of the Wilaya of Illizi.

The region lies at an altitude of 432 m and covers an area of 4000 km², according to the following coordinates (TFT) field are 28.554° N, 7.225° E. It sits on a large Paleozoic north-south trending arch at the southern edge of the Ghadames Basin.

The primary hydrocarbon reservoir is the Uppermost Ordovician (IV-3 unit) sandstone, characterized by a sub-normal pressure regime and a narrow drilling mud weight window due to reservoir depletion[6].

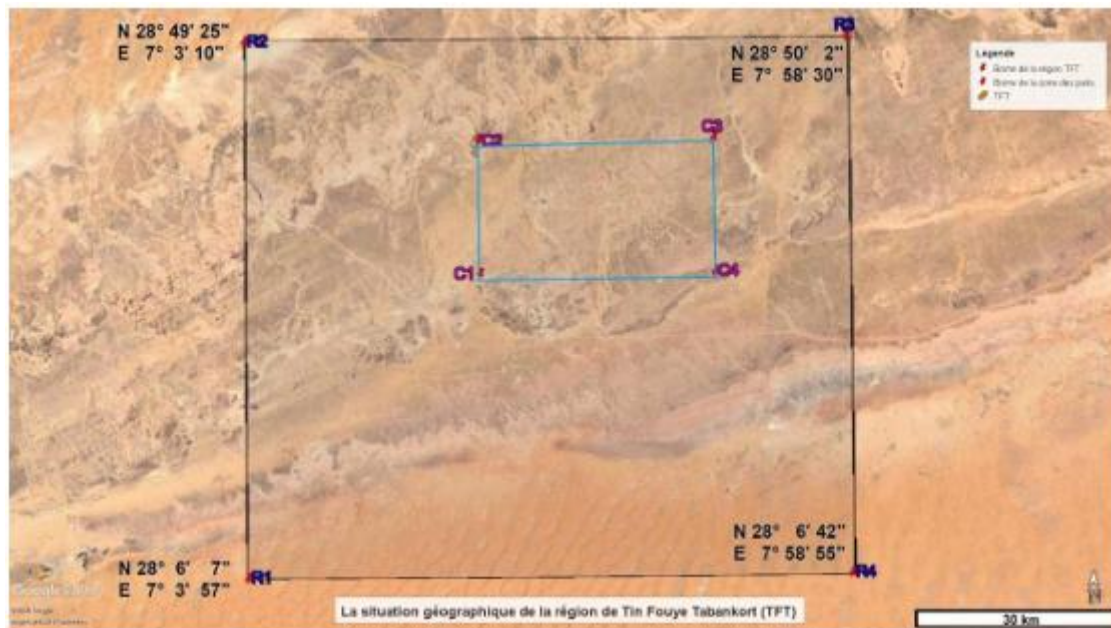


Figure 0-1: Geographical location of Tin Fouye Tabankort (TFT) [6].

I.2.2 Presentation of the TFT site

The regional management of (TFT), is part of the production division of the company. SONATRACH. It is responsible for the production of oil from the TFT fields and for the management of all its divisions. The Tin Fouye Tabankort Area is located in the western part of the Illizi Basin, 284 kilometers from In Amenas, between the intersection of two wadis (Tin Fouye) and an artesian well (Tabankort).

The regional division includes nine fields of different sizes and different processing units: oil separation centers, oil collection centers, water production and injection centers (for pressure maintenance), an associated gas processing unit and gas compression units (gas lift), and is interested in the dehydration section and the gas processing section.

The TFT region, composed of two sectors (north and south), ranks as the second largest oil producing region after Hassi Messaoud. In addition, gas development in partnership between SONATRACH, TOTAL, and REPSOL has made TFT an important gas producing area.

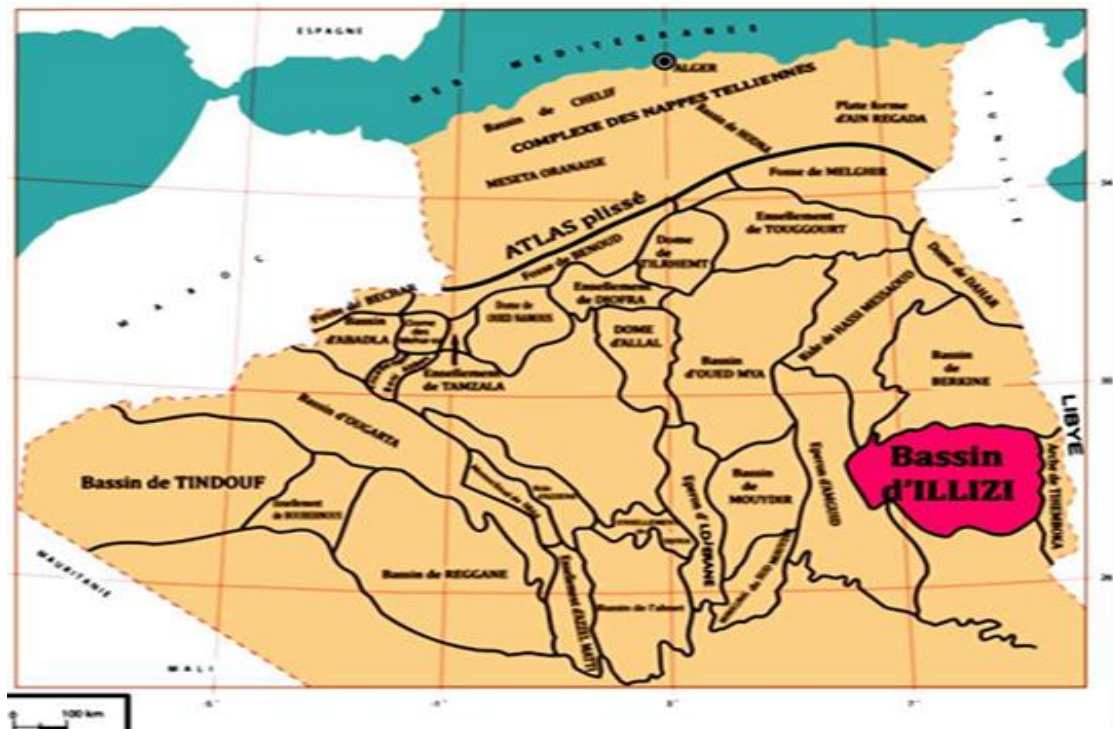


Figure 0-2: The geographic situation of TFT [6].

I.3 Description of the TFT reservoir

The Tin Fouye Tabankort (TFT) field has a complex reservoir structure with hydrocarbons found in two primary stratigraphic zones:

1. **Uppermost Ordovician Sandstone:** This is the primary reservoir, specifically in the IV-3 and IV-2 units. It is characterized as a mature, lean gas-condensate reservoir with an initial pressure **2,683 psi** slightly above its dewpoint pressure (2,619 psi). The reservoir exhibits a sub-normal pressure regime and its quality is enhanced by the development of a fluvioglacial facies from the last Ordovician ice period. This zone contains a large gas cap and a major oil accumulation.
2. **Upper Silurian to Lower Devonian Zone (F6 Reservoir):** This secondary reservoir consists of interbedded sandstones and shales (**subdivided into units M1, M2, A, B1, B2, C1, C2, C3**) deposited in offshore coastal bars and tidal channels. Reservoir quality is highest in the medium- to coarse-grained, clay-poor sands of units **C1 and B2**, which have significant secondary porosity. This zone contains several oil fields on northward-plunging nose.

I.4 Different Deposits of TFT

The Tin Fouye Tabankort region covers an area of 4,000 km² and includes several deposits:

- **TFT Deposit:** Discovered in 1967 and put into service in 1968, it appears as an oil ring capped by a large gas cap. It represents 55% of the reserves in place in the TFT region. It has more than 100 wells, currently producing both naturally flowing and partially by gas lift.
- **Tin Fouye Deposit:** The first deposit discovered in 1961 and put into service in 1963. Located south of TFT, it covers 306 km² and represents 22% of the reserves. Oil is found in the Devonian F6 unit (1,300 m) and is produced using gas lift.
- **Amassak Deposit:** Located 25 km northwest of TFT, discovered in 1970 and put into service in 1974. It represents 10% of TFT reserves and has more than 40 wells. Oil and gas reserves are in the Ordovician 4-3 unit (2,000 m), produced using both mechanical pumping (since 1995) and gas lift.
- **Djoua Deposit:** Situated 30 km southeast of TFT, discovered in 1966 and put into production in 1968. It produces oil mainly from the Devonian F6 reservoir (C1 unit, 1,500 m) and from the Gothlandian AV-III and M1-X units (1,600 m), using ESP.
- **Tamendjlet Deposit:** Located about 6 km northwest of TFT, discovered in 1970 and put into service in 1974. Oil from the Devonian F6 reservoir is produced by gas lift.
- **Hassi Mazoula North Deposit:** Discovered in 1958 and put into production in 1965, with 2 wells in operation. Oil is produced by electric pumping from the F6 reservoir.
- **Hassi Mazoula South Deposit (HMZ-B):** Discovered in 1963 and put into production in 1966, with 5 wells in operation. Currently, only the F6 reservoir produces oil by electric pumping.
- **Hassi Mazoula (B) Deposit:** Discovered in 1966 and put into service in 1967, covering 4.4 km² with 4 wells in operation. Oil accumulations are produced by ESP.

CHAPTER II

OVERVIEW OF WELL

ACTIVATION



Chapter II: Overview of well activation

II.1 Introduction

Most oil-producing wells will flow naturally for some period of time after they begin producing. Reservoir pressure and formation gas provide enough energy to bring fluid to the surface in a flowing well. As the well produces this energy is consumed, and at some point, there is no longer enough energy available to bring the fluid to the surface and the well will cease to flow.

If the desired rate is greater than the reservoir energy can deliver, it becomes necessary to put the well on some form of well activation to provide the energy to bring the fluid to the surface.[1]

II.2 Well Activation

Well activation is the process of starting an oil or gas well into production or restoring its ability to produce efficiently after decline in reservoir pressure over time. This process involves a variety of operational and technical procedures designed to improve the flow of hydrocarbons from the reservoir to the surface. Depending on the condition of the well, activation may include well cleaning, stimulation treatments such as acidizing or hydraulic fracturing, Artificial lift systems are also installed to activate and put wells on service, when reservoir doesn't have enough energy to raise the fluid from the bottom of the well to the treatment facilities or the productivity index of the well is considered insufficient. [1]

There are two parameters that can be acted on: $Pre \leq \frac{H \times d}{10,2} \dots\dots\dots(1)$

- Height reduction “H” by installing a pump in the well.
- Column weight reduction “d” by injecting less dense gas (natural gas...).

II.3 Types of Artificial Lift Systems

Artificial-lift methods fall into two groups, those that use pumps and those that use gas.

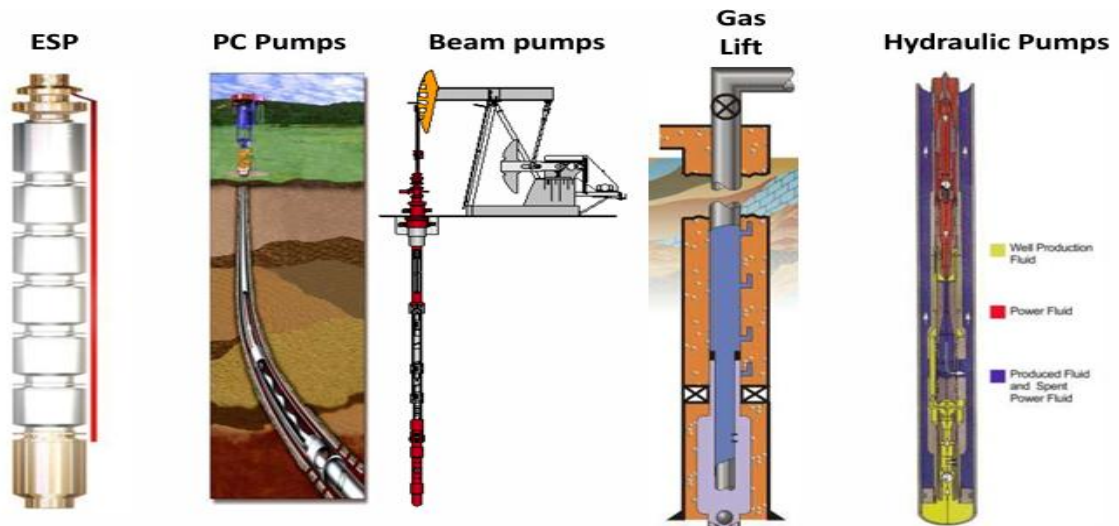


Figure 0-1: Artificial Lift methods [16].

II.3.1 Pump Types

- **Beam Pumping / Sucker Rod Pumps (Rod Lift)**

Oldest and most widely used method of artificial lift. A motor drives a beam, connected to a polished rod passing into the tubing via a stuffing box. The rod string continues down to the oil level, rod pumps combine a cylinder (barrel) and piston (plunger) with valves to transfer well fluids into the tubing and displace them to the surface. [2]

- **Electric Submersible Pumps (ESP):**

Electric submersible systems use multiple pump stages mounted in series within a housing, mated closely to submersible electric motor on the end of tubing and connected to surface controls and electric power by an armor protected cable.

- **Progressive Cavity Pumps (PCP's)**

Consist of a surface drive, drive string and downhole. The PC pump is comprised of a single helical-shaped rotor that turns inside a elastomer-lined stator. The stator is attached to the production tubing string and remains stationary during pumping. The rotor is attached to a

sucker rod string which is suspended and rotated by the surface drive. Rotation of the rod string by means of a surface drive system causes the rotor to spin within the fixed stator, creating the pumping action necessary to produce fluids to surface. PCP usually rotates between 300 and 600 rev/min. [2]

• Subsurface Hydraulic Pumps

Consist of a surface power fluid system, a prime mover, a surface pump, and a downhole jet or piston pump. Crude oil or water (power fluid) is taken from a storage tank and fed to the surface pump. The power fluid is controlled by valves at a control station and distributed to one or more wellheads and directed to the downhole jet or piston hydraulic pump. There are two pumps (Jet pump and Piston pump). [2]

II.3.2 Gas Method

• Gas Lift

Gas lift is a method of artificial lift that uses an external source of high-pressure gas for supplementing formation gas to lift the well fluids. The principle of gas lift is that gas injected into the tubing reduces the density of the fluids in the tubing, and the bubbles have a “scrubbing” action on the liquids. Both factors act to lower the flowing bottomhole pressure (BHP) at the bottom of the tubing. There are two basic types of gas lift in use today continuous and intermittent flow.[2]

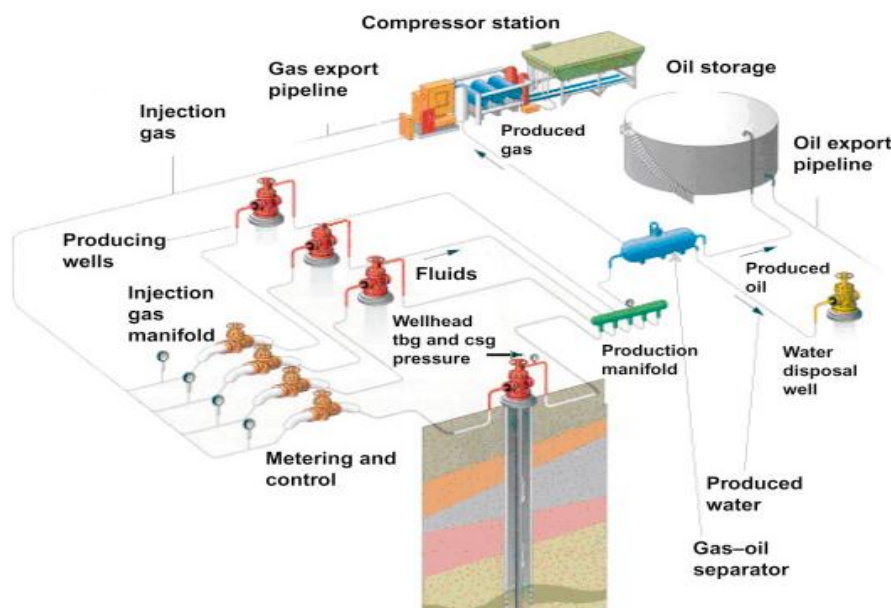


Figure 0-2: Basic components of GL system [5].

II.4 Selection of the Artificial Lift Method

Each method has applications for which it is the optimum installation. Many factors are involved in selection (designing) of the best artificial lift method to suit the conditions

- **Well depth:** The well depth dictates how much surface energy is needed to move fluids to surface, and may place limits on sucker rods and other equipment.
- **Completion type:** Completion and perforation skin factors affect inflow performance.
- **Casing and tubing sizes:** Small-diameter casing limits the production tubing size and constrains multiple options. Small-diameter tubing will limit production rates, but larger tubing may allow excessive fluid fallback.
- **Wellbore deviation:** Highly deviated wells may limit applications of beam pumping or PCP systems because of drag, compressive forces and potential for rod and tubing wear
- **Field location:** In offshore fields, the availability of platform space and placement of directional wells are primary considerations. In onshore fields, such factors as noise limits, safety, environmental, pollution concerns...
- **Power sources:** The availability of electricity or natural gas governs the type of artificial lift selected. Diesel, propane or other sources may also be considered.
- **Gas liquid ratio:** A high GLR generally lowers the efficiency of pump-assisted lift.
- **Viscosity:** Viscosities less than 10 cp are generally not a factor in selecting a lift method; high-viscosity fluids can cause difficulty, particularly in sucker rod pumping.
- Cost & Availability of Injection Gas and Electric Power.
- **Well problems** (Sand, Temperature, Scale, H₂S, PARC... etc). [2]

II.5 Gas Lift Applications

Gas lift is used to well activation, but there are other uses. Among the uses of gas lift, we can mention:

- Increase production rates in flowing wells.
- Unloading wells after neutralization and interventions.
- Injector well cleaning (injector clean up).
- Water wells.

II.6 Compositions of the injected gas

The gas for injection, already treated and compressed beforehand, has the following composition:

Table 0-1: Injected gas compositions [9]

Components	N2	CO ₂	C1	C2	C3	i-C4	n-C4	n-C5	C6	C7
Mole. Fraction	5.38	0.31	82.98	8.89	1.69	0.28	0.39	0.06	0.02	0.00

II.7 Principal gas lift parameters

II.7.1 Wellhead pressure

Lower WHP or surface backpressure reduces the flowing bottom-hole pressure and optimizes gas lift performance by minimizing the required injection gas volume for a target liquid production rate. This leads to improved lifting efficiency and reduced constraints on the gathering system.

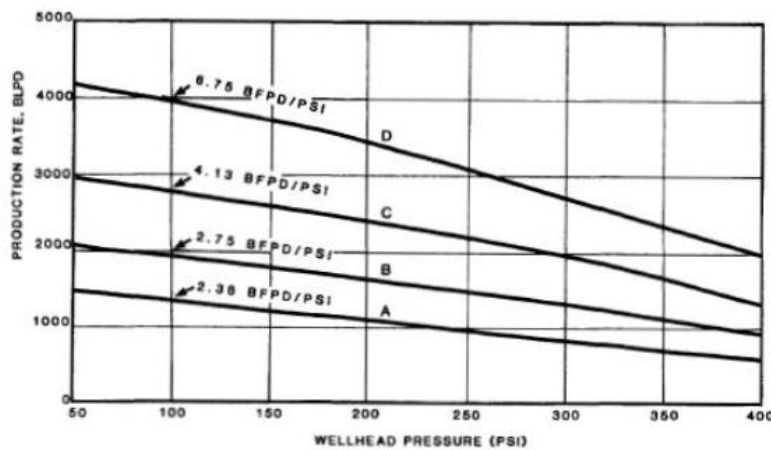


Figure 0-3: The effects of wellhead backpressure for a specific set of wells [8].

II.7.2 Gas injection pressure

The gas pressure to be injected affects the number of discharge valves, so injection with high pressure can allow operation without discharge valves (single point), which greatly simplifies well design, operation and maintenance. [8]

II.7.3 Gas injection depth

Deeper gas injection improves gas lift efficiency by reducing the hydrostatic pressure over a longer section of the wellbore, leading to lower flowing bottom-hole pressure and higher production rates. Shallow or faulty injection reduces efficiency and may cause significant production losses. Optimal designs therefore place the injection point as deep as possible, often using packers with by-pass to maximize performance.[8]

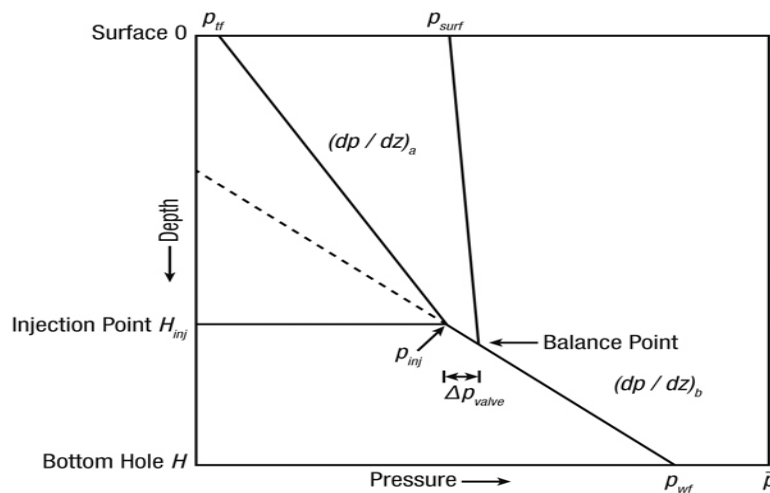


Figure 0-4: Continuous gas lift with pressures and G_p versus depth [8].

II.7.4 Gas injection rate

The gas injection rate is the volume of gas injected per unit time in a gas lift system. It controls the reduction of bottom-hole pressure and directly influences production rate. An optimal rate maximizes production efficiency, while too low or too high rates reduce performance.[8]

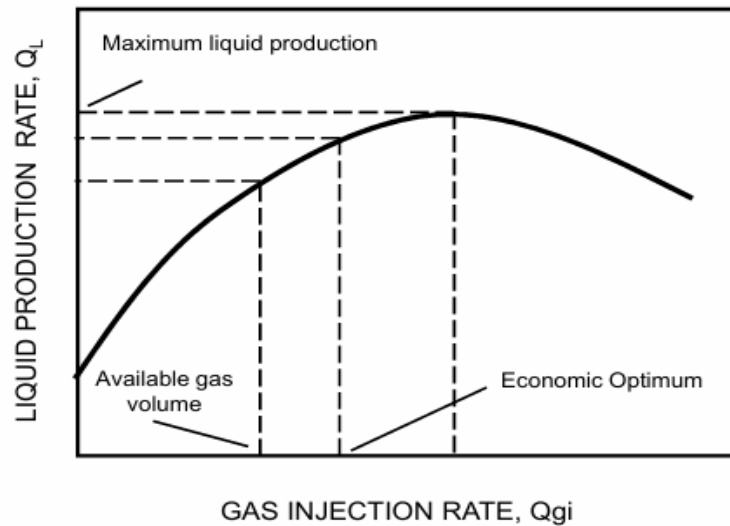


Figure 0-5: Effect of gas injection rate. [8]

II.7.5 Productivity Index (PI)

The Productivity Index (PI=J) measures the daily production of liquid for each pound per square inch of reservoir pressure drawdown. Gas lift, like other well activation methods, affects gas lift by lowering dynamic bottomhole pressure, especially in wells with a significant PI, where gas lift offers high flow rates.

$$PI = \frac{q}{P_{re} - P_{wf}} \dots\dots\dots (2)$$

Where:

- PI: Productivity Index (BLPD/psi)
- q: Liquid Production Rate (BLPD)
- Pre: Reservoir Pressure (psig)
- Pwf: Flowing bottomhole pressure (psig)

II.8 Inflow Performance of Oil Wells

The success of a gas lift design depends heavily upon the accurate prediction of fluid flow into the wellbore from the formation. The ability of a well to give up fluids represents its inflow performance. One simple method of predicting a well's inflow performance is the calculation of a productivity index (PI). The PI is a ratio of fluid production rate (Q) in (BPD) to the difference between the Static Bottom Hole Pressure and the Flowing Bottom Hole Pressure in (Psig). This ratio is expressed in the equation (2),[7]

II.8.1 Inflow Performance Relationship (IPR)

Engineers use the inflow performance relationship (IPR) to evaluate reservoir deliverability in reservoir and production engineering. The IPR curve is a graphical presentation of the relationship between the flowing bottom-hole pressure and the liquid production rate.[6]

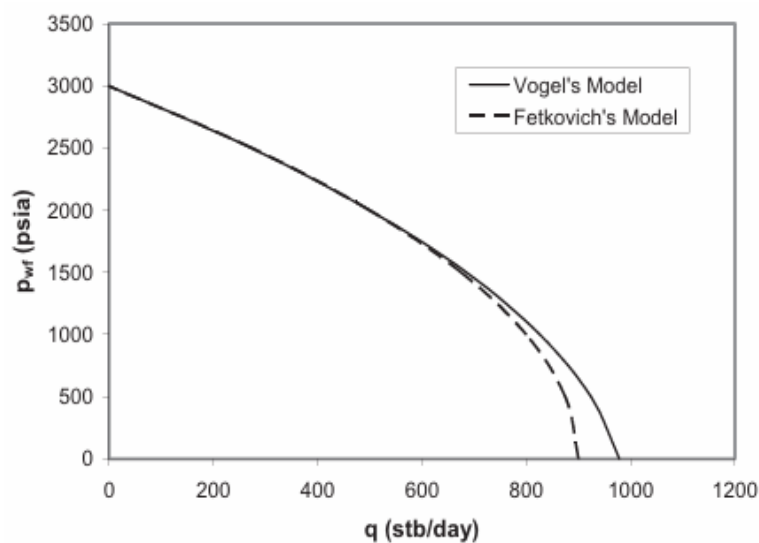


Figure 0-6: Inflow Performance Relationship. [4]

II.9 Types of gas lift

II.9.1 Continuous Flow Gas Lift

Is an artificial lift method in which gas is continuously injected into the production tubing at a specific depth, pressure, and flow rate to reduce fluid density and maintain the flow of hydrocarbons to the surface.

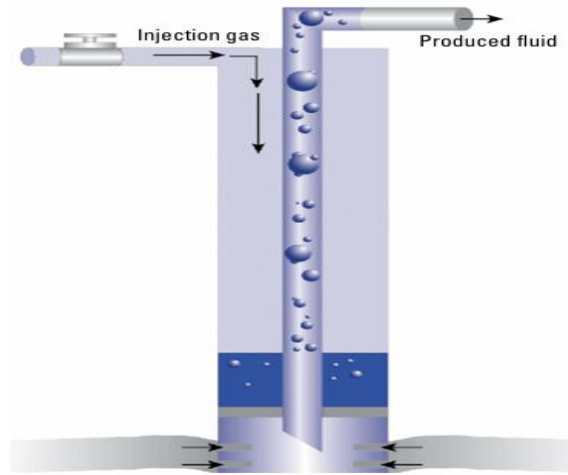


Figure 0-7: Continuous Flow Gas Lift.[11]

While Continuous Gas Lift (CGL) is widely implemented for high-productivity wells, it becomes inefficient as reservoir pressure declines. Therefore, Intermittent Gas Lift (IGL) emerges as the standard alternative for low-productivity or depleted wells, as detailed in the following section.

II.9.2 Intermittent Gas Lift (IGL)

II.9.2.1 Principle and Suitability of Intermittent Gas Lift (IGL)

While Continuous Gas Lift (CGL) relies on steady gas injection to reduce fluid density and is highly effective for high-productivity wells, it becomes inefficient as reservoir pressure declines. For low-productivity wells or those experiencing significant pressure depletion, Intermittent Gas Lift (IGL) provides a more appropriate and efficient alternative [3].

Unlike the continuous fluid density reduction process in CGL, the IGL process (Figure II-9) relies on the periodic, high-pressure injection of gas into the tubing. This injected gas physically displaces the accumulated fluid above the operating gas lift valve, lifting it to the surface as a solid liquid slug. The operating principle of IGL is fundamentally different and mechanically more intricate than CGL. It encompasses several design variations and operates through a cyclic process characterized by distinct, dynamic stages with multiple interacting multiphase flows occurring in each phase.

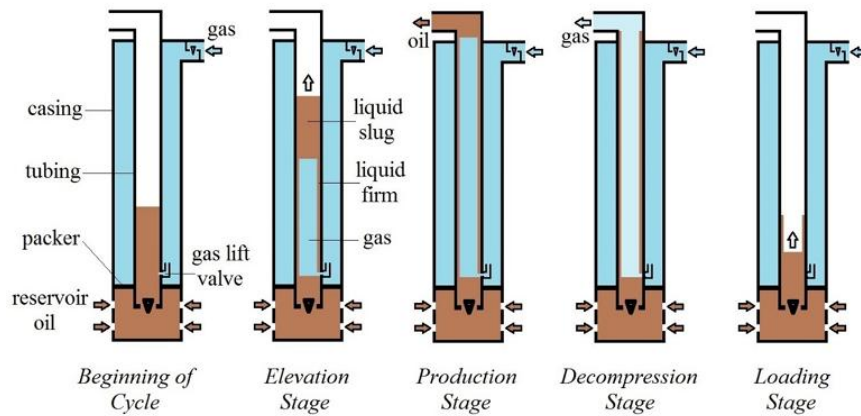


Figure II-8: Flows in IGL system [11]

II.9.2.2 Description of the Production Cycle:

Intermittent gas lift (IGL) production is managed via an automated surface injection system (Figure II-9). The surface control valve is programmed based on a specific time cycle; for instance, it opens for a predetermined duration (e.g., 30 min) to inject gas lift through the deepest operating gas lift valve. Meanwhile, the remaining side-pocket mandrels (SPMs) are isolated using dummy valves, consistent with the completion design in the TFT field. Following the injection phase, the surface valve closes to allow for bottomhole liquid accumulation.

Solar-powered cycle controller (RTU) for valve timing regulation.

Pneumatic diaphragm control valve (Motor valve)



Figure II.9: Surface Intermittent Gas Lift (IGL) Injection Control System

II.9.2.3 Types of Completions for Intermittent Gas Lift:

- **Conventional Intermittent Lift (IL)**

Conventional intermittent gas lift (Figure II-10) operates by injecting high-pressure gas into the well at timed intervals, allowing it to accumulate beneath a slug of liquid. Once enough pressure builds up, the gas rapidly expands, pushing the liquid slug to the surface. This method is widely used when reservoir pressure declines and continuous gas lift become inefficient. However, it has inherent challenges, such as liquid fallback, which reduces overall efficiency. To optimize its performance, engineers carefully control the injection cycle and timing to maximize the lift efficiency while minimizing gas consumption.

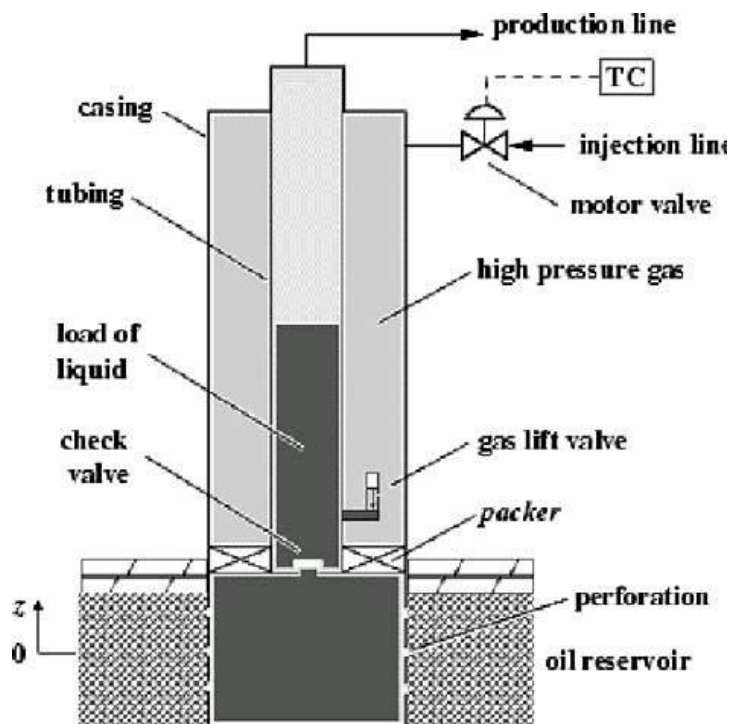


Figure II-10: Conventional Intermittent Lift [3]

- **Chamber Lift (CL)**

Chamber lift is a specialized variation of intermittent gas lift (Figure II-11) designed for wells with high productivity indexes. It involves a subsurface chamber that temporarily stores liquid before being lifted to the surface. By allowing larger fluid slugs to form before gas injection, chamber lift increases production efficiency and reduces the number of gas injection cycles required. This method is particularly useful for wells with significant liquid accumulation and is known to enhance recovery by reducing fallback losses compared to conventional intermittent lift.

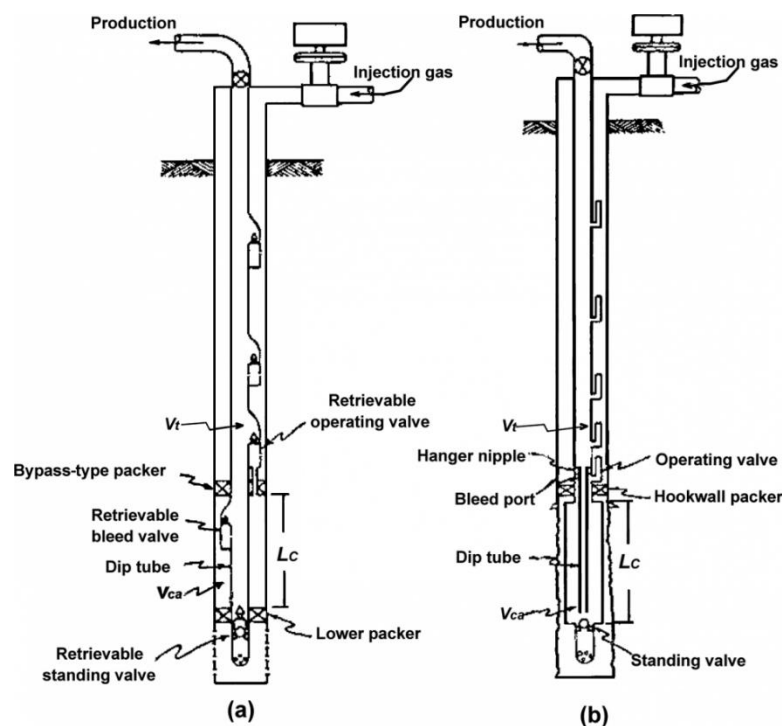


Figure II.11: Chamber Lift [3]

II.9.2.4 Pilot Valves in Intermittent Gas Lift

Pilot valves play a critical role in the operation of intermittent gas lift systems by controlling the gas injection into the production tubing. Their design and function enable precise gas flow regulation, optimizing the efficiency of the artificial lift process.

- **Structure and Functionality**

A pilot valve consists of two main sections:

- a. **Upper Section** – Determines the opening and closing pressures of the valve.
- b. **Lower Section** – Regulates the instantaneous gas flow rate into the production tubing.

The upper section of the valve operates based on the balance between the injection pressure, production pressure, and the force exerted by a nitrogen-charged dome or a spring mechanism. When the injection pressure exceeds a preset threshold, the valve opens, allowing gas to flow through the lower section into the tubing. Once the gas has displaced the liquid slug to the surface, the valve closes, ending the injection cycle.

- **Types of Pilot Valves**

Pilot valves can be categorized based on their operating mechanism:

1. **Injection-Pressure-Operated (IPO) Pilot Valves** – These valves open and close based on the pressure differential between the annulus and tubing, making them the most commonly used type.
2. **Production-Pressure-Operated Pilot Valves** – These rely on changes in production pressure, but their use has declined due to difficulty in controlling cycle timing effectively.

- **Advantages of Pilot Valves**

1. **High Gas Flow Rate Control** – The lower section of the pilot valve allows for high instantaneous gas flow rates, which are essential for efficient intermittent gas lift operations.
2. **Precise Opening and Closing Pressures** – The upper section of the valve ensures accurate pressure regulation, optimizing gas injection cycles.
3. **Flexibility in Gas Lift Optimization** – By adjusting the calibration settings, pilot valves can be tailored to the specific needs of the well, improving lifting efficiency.
4. **Reduction of Gas Consumption** – Properly designed pilot valves contribute to minimizing the injection gas-to-liquid ratio, reducing operational costs.

- **Challenges and Common Failures**

Despite their advantages, pilot valves may experience operational challenges:

1. **Erosion and Wear** – Continuous gas flow can erode valve seats, reducing effectiveness.
2. **Blockage Due to Solid Particles** – Debris in the gas lift system may clog the internal components, leading to valve malfunction.
3. **Seal and Bellows Failure** – Over time, the bellows may flatten or the seals may degrade, affecting valve performance.
4. **Erratic Closing Pressure** – The dynamic nature of gas flow can cause the valve to close at pressures higher or lower than the theoretical value, impacting cycle efficiency.

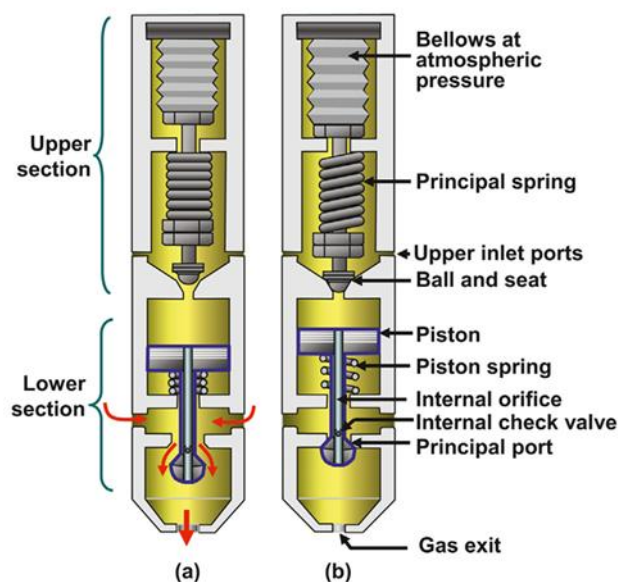


Figure II-12: IGL Pilot Valve in (a) Opened and (b) Closed Positions [10]

II.10 Flow Performance with Gas Lift

II.10.1 Effect of Gas Lift on IPR

Gas lift doesn't directly modify the reservoir inflow behavior, but it improves well production by reducing the flowing bottom-hole pressure (P_{wf}). The reduction in bottom-hole pressure increases Drawdown between the reservoir and the wellbore, resulting in higher production rates. Wells with high productivity index (PI) generally show a stronger response to gas lift operations. [3]

II.10.2 Vertical Lift Performance (VLP)

The Vertical Lift Performance (VLP) curve describes the pressure required to lift fluids from the bottom of the well to the surface. In gas lift systems, injected gas reduces the density of the fluid column, thereby decreasing hydrostatic pressure losses inside the tubing. As a result, the VLP curve shifts downward, indicating improved lifting efficiency and lower flowing bottom-hole pressure. [3]

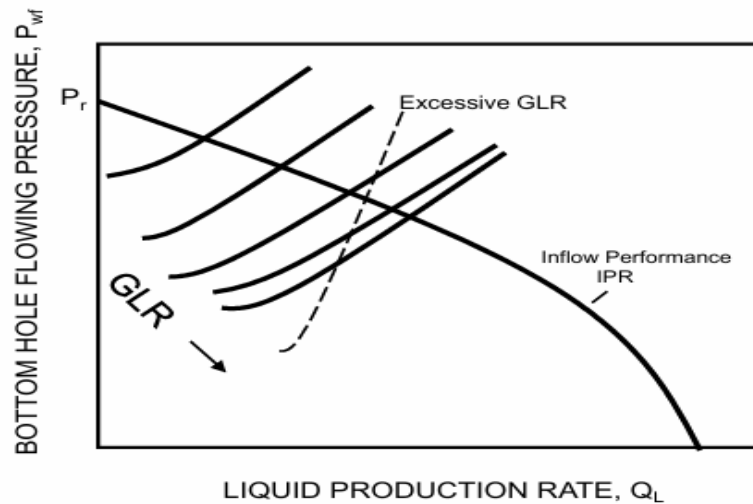


Figure 0-13: Gas lift well analysis. [13]

II.10.3 Operating point

The operating point is the intersection between the IPR and VLP curves. It represents the stable production condition of the well, where the inflow from the reservoir equals the outflow through the production tubing. Gas lift modifies the VLP curve by lowering pressure losses, which shifts the operating point toward higher production rates and lower bottom-hole pressures. [3]

II.11 Flow Assurance Issues in Gas Lift

Flow assurance in gas lift refers to problems that affect the safe and continuous flow of fluids from the reservoir to the surface. The main issues include: [12]

- **Hydrate formation:** Occurs when gas and water combine under high pressure and low temperature, forming solid crystals that may block tubing and valves.

- **Wax deposition:** Paraffin wax can accumulate in the tubing due to temperature reduction, restricting flow.
- **Asphaltene deposition:** Heavy organic compounds may precipitate because of pressure and composition changes during gas lift operations.
- **Scale formation:** Mineral deposits such as calcium carbonate or barium sulfate can reduce tubing diameter and damage valves.
- **Corrosion:** Presence of CO₂, H₂S, and water may corrode tubing and gas lift equipment.
- **Slugging and unstable flow:** Irregular gas liquid flow can reduce lifting efficiency and create operational instability.

CHAPTER III

HYDRATE

FORMATIONS ISSUES



Chapter III: Hydrate formation issues

III.1 Introduction

Gas hydrate formation represents one of the most critical flow assurance challenges in oil and gas production systems, particularly in gas lift operations. These crystalline solids can form under conditions of high pressure and low temperature in the presence of free water and light hydrocarbons. Once formed, hydrates may agglomerate and create plugs in pipelines, valves, and injection lines, leading to severe operational disruptions and production losses.

In mature fields such as TFT, hydrate formation is especially problematic in gas lift systems, where pressure drops across choke valves induce significant cooling (Joule–Thomson effect), favoring hydrate crystallization. Despite the implementation of conventional mitigation techniques such as methanol or glycol injection, hydrate-related issues persist, particularly during winter periods.

This chapter presents the fundamental mechanisms governing hydrate formation, the thermodynamic and operational conditions that promote their appearance, and the main mitigation strategies currently applied in the industry. Special emphasis is placed on the limitations of conventional methods, which motivates the investigation of alternative approaches.

In this context, intermittent gas lift (IGL) emerges as a promising technique not only for artificial lift optimization but also for reducing hydrate formation risks by modifying pressure-temperature dynamics and gas injection patterns. This concept forms the basis of the present study and will be explored in detail in the following chapter.

III.2 Fundamentals of Hydrate structure and Composition

III.2.1 Definition

Gas hydrates referred to as clathrate hydrates, are crystalline solid compounds formed when small gas molecules become trapped within a lattice of hydrogen-bonded water molecules. The term clathrate originates from the Latin “clathrates”, meaning “cage” which reflects the cage-like architecture of the host structure. Under the right thermodynamic conditions specifically elevated pressure and low temperature in the presence of sufficient water these cage structures form spontaneously and are stabilized by Van Der Waals interactions between the guest molecule and the surrounding water framework.

III.2.2 Structures (I, II, H)

Gas hydrates crystallize into three primary structures: **sI**, **sII**, and **sH** which are defined by the specific geometry and arrangement of their water-molecule cages.

- ❖ **Structure I (sI):** Structure I hydrates are stabilized by small gas molecules such as methane, ethane, and carbon dioxide. The crystal lattice is cubic and consists of two types of cages: small and medium. In total, 46 water molecules form 2 small cages and 6 medium cages. This structure is the most common in natural gas systems, especially in methane-dominated reservoirs and pipelines.
- ❖ **Structure II (sII):** Structure II hydrates are formed when slightly larger molecules, such as propane, isobutane, or nitrogen, are present. The lattice is also cubic but contains larger cages compared to sI. A unit cell is composed of 136 water molecules forming 16 small cages and 8 large cages. This structure is typical in mixed hydrocarbon systems where heavier gases coexist with lighter ones.
- ❖ **Structure H (sH):** Structure H hydrates are less common and require very large hydrocarbon molecules, such as iso-pentane or cyclohexane, along with smaller stabilizing molecules like methane. The lattice is hexagonal and contains three cage types: small, medium, and very large. A unit cell is made of 34 water molecules forming 3 small cages, 2 medium cages, and 1 large cage. This structure is important in complex hydrocarbon mixtures but rarely occurs naturally.[14]

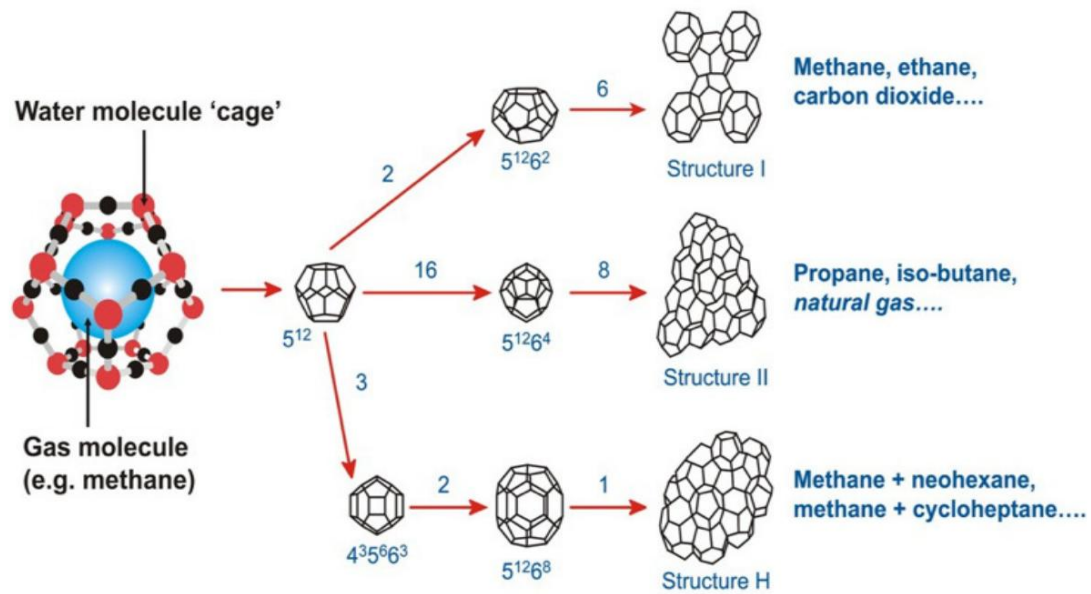


Figure 0-1: Three structural types of hydrates.[14]

III.2.3 Phase behavior

Hydrate formation generally requires four main conditions: free water, hydrate-forming gases, high pressure, and low temperature. Most hydrocarbons in the oil and gas industry form hydrates under high-pressure conditions, with lighter hydrocarbons requiring higher pressures than heavier ones.

Water salinity also affects hydrate formation, since higher salinity increases the pressure needed for hydrate stability. During hydrate formation in salty water, the remaining water becomes more saline, making the process partially self-inhibiting. In addition, chemicals such as methanol or glycol increase the pressure required for hydrate formation. This principle is widely used in hydrate risk management through thermodynamic inhibitors.[12]

III.3 Hydrate formation

III.3.1 Hydrate formation scenarios

As long as the requisites for hydrate formation are present, that is, high pressure, low temperature, presence of hydrate formers and water, there are risks of hydrate formation. The following are a few common scenarios to consider for the potential risk of hydrate formation in upstream production.[12]

- **Shut-in**

Fluid temperature typically drops after production is shut-in and the flow has stopped in cases where the environmental temperature is lower than the production fluid temperature, e.g., deepwater, winter time. The pressure can also start building up after shut-in. Both these changes can eventually push the system into the hydrate formation conditions in either wells or flowlines.

- **Cold restart**

If the shut-in period is long enough to push the system into hydrate conditions, restarting the production from this state can pose a high hydrate formation risk since the flow turbulence can greatly accelerate the mass transfer and cause rapid hydrate formation.

- **Steady state**

Some production systems can enter hydrate formation condition during steady state. This is less common for black oil system, but more common for gas system due to the much smaller heat capacity and lack of insulation.

- **Gas injection, gas lift, or gas export**

These gas systems rely on dehydration to control the risk of hydrate. However, the dehydration can sometimes underperform, or the water content measurement/reading can be faulty. Hydrate can form and plug the line in these scenarios.

III.3.2 Hydrate formation mechanism

The molecular mechanism of hydrate formation is still not fully understood. Hydrate formation begins with the nucleation stage, where small unstable molecular clusters containing hydrate-forming gases are formed in the presence of free water, high pressure, and low temperature. These nuclei gradually grow into crystalline hydrate particles during the growth stage. As hydrate particles increase in size, they agglomerate and adhere together, forming larger hydrate masses. From a macroscopic perspective, hydrates mainly form at gas/water or oil/water interfaces, and continuous agglomeration may eventually lead to hydrate plug formation, causing partial or complete blockage in pipelines and production tubing. Experimental studies by Jeong et al. confirmed this conceptual hydrate formation mechanism under high-pressure natural gas conditions.[12]

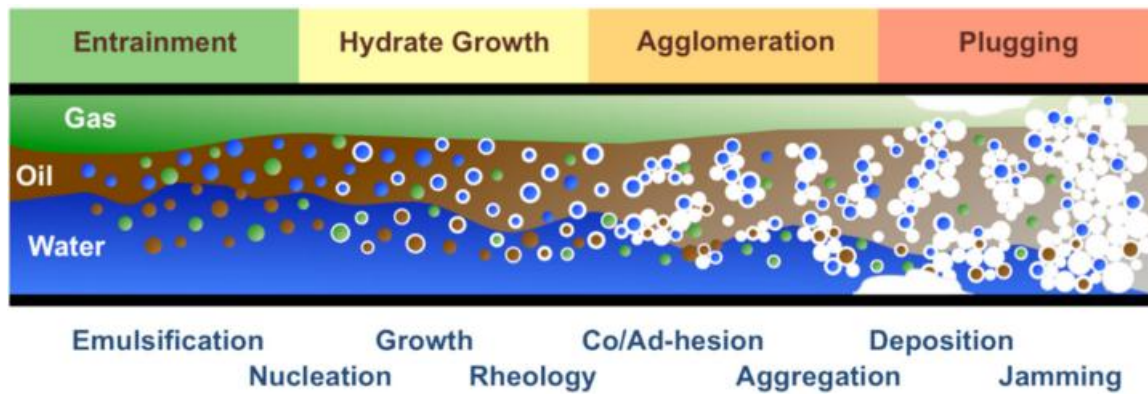


Figure 0-2: Typical conceptual hydrate formation model in a multiphase flow system [12].

III.4 Factors governing hydrate formation

Hydrate formation is governed by a combination of thermodynamic and kinetic factors, requiring the presence of water, light gas molecules, low temperatures, and high pressures.

Key influences include: [14]

- **Temperature and Pressure:** Hydrate formation occurs only under conditions of low temperatures and high pressures. Elevated pressures and reduced temperatures decrease the "induction time" (the time it takes for crystals to form) and increase crystal growth rates.
- **Gas Composition:** The presence of lightweight "guest" molecules (such as methane, ethane, propane, carbon dioxide, and hydrogen sulfide) is required to fill the water cages. Gases with specific gravity favoring hydrate formation accelerate the process.
- **Water Salinity:** Salts and dissolved minerals inhibit hydrate formation by disrupting the hydrogen bonds of water, effectively raising the required pressure and lowering the temperature needed to form hydrates.
- **Turbidity and Agitation:** Fluid movement, high flow rates, and vortices increase the gas-water contact area and turbulence, which drastically reduces induction time and encourages crystal formation.
- **Chemical Inhibitors:** Thermodynamic or kinetic inhibitors (e.g., Mono Ethylene Glycol (MEG), methanol, or polymeric kinetic inhibitors) are commonly used in industrial settings to alter growth morphology and safely extend the operating envelope.

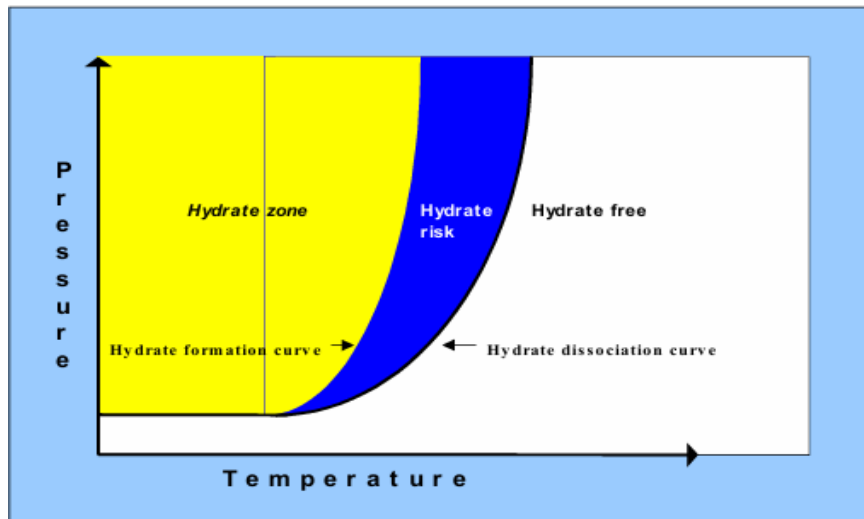


Figure III.3: Typical hydrate formation diagram.[14]

III.5 Gas hydrate Problem in oil and gas industry

- **Pipeline Blockage**

Gas hydrates can form solid plugs inside pipelines, completely obstructing the flow of oil and gas. Such blockages result in immediate production shutdowns, necessitating extensive and costly mechanical or chemical remediation efforts. In offshore operations, hydrate plugs are particularly dangerous because access is limited. Pipeline blockage is considered the most severe hydrate-related flow assurance problem [14].



Figure III.4: AI-generated illustrative image showing hydrate blockage inside a gas lift injection line.

- **Pressure and Flow Instability**

Hydrate buildup increases friction in the pipeline, leading to sudden pressure drops and unstable flow regimes. These fluctuations can damage compressors, pumps, and other surface equipment. Flow instability also complicates production forecasting and reservoir management. As a result, hydrate formation directly reduces operational reliability.

- **Equipment Damage**

Hydrate particles and slurries can erode valves, chokes, and subsea equipment. When hydrates accumulate, they increase slurry viscosity, causing mechanical stress on production systems. This often leads to premature equipment failure and expensive replacements. Long-term hydrate exposure significantly reduces system integrity.

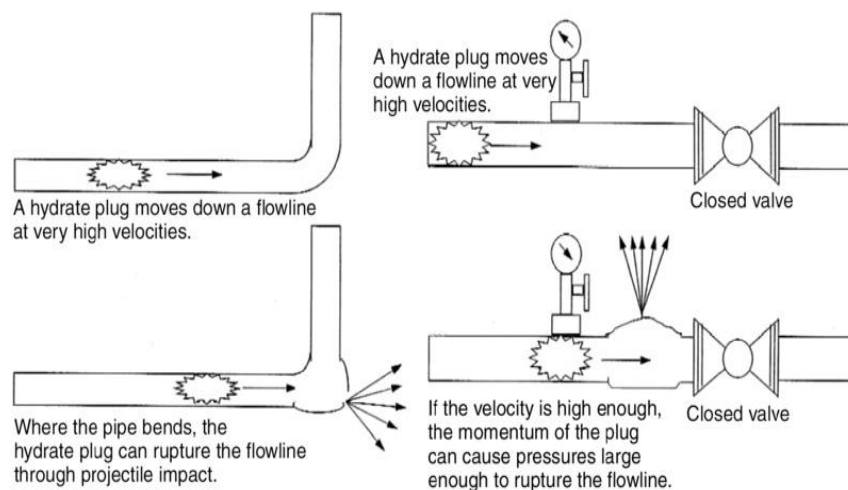


Figure III.5: Hazards of Hydrate Plug Movement in Flowlines [12].

- **Economic Losses**

Production downtime caused by hydrate plugs can result in significant financial losses in onshore oil and gas operations. Hydrate remediation often requires costly chemical injection, heating, depressurization, or mechanical removal procedures. In remote onshore fields, these interventions may considerably increase operational and maintenance costs. Therefore, hydrate formation represents both a technical and economic challenge for production operators.

III.6 Ways to prevent hydrate formation

The following are the thermodynamic ways to prevent the hydrate formation:

1. Reducing the water concentration from the system.
2. Operating at temperatures above the hydrate-formation temperature for a given pressure by insulating the pipelines or applying heat.
3. Operating at pressures below the hydrate-formation pressure for a fixed temperature.
4. line heaters and insulated/heat traced lines will keep the temperature of flowing gas above the hydrate formation temperature within a specific range of gas flow rates – a very effective method for steady flow conditions
5. Adding inhibitors such as salts, methanol, and glycols to inhibit the hydrate formation conditions and shift the equilibrium curve to higher pressure and lower temperature. Inhibitors are added into processing lines to inhibit the formation of hydrates.

There are two kinds of inhibitors: thermodynamic inhibitors (THIs) and low-dosage inhibitors. The thermodynamic inhibitors (Methanol and MEG) have been used for a long time in the industry and act as antifreeze. The low-dosage inhibitors have recently been developed and their usage modifies the rheology of the system rather than changing its thermodynamic states. These inhibitors work at low concentrations, lower than or equal to 1 wt%; therefore, the use of this technique reduces the environmental concerns and since no regeneration units are required, it results in reduction of capital cost. The low-dosage inhibitors are divided into kinetic inhibitors (KHIs) and anti-agglomerants (AAs). The kinetic inhibitors are commonly water-soluble polymers that delay the nucleation and growth of hydrate crystals, while the anti-agglomerants are usually surfactants and miscible in both hydrocarbon and water, so they impede the agglomeration of hydrate crystals for a period of time without interfering with crystal formation.[14]

Table III.1: Comparison of Hydrate Inhibition Strategies [12].

Inhibitor Category	Specific Type	Typical Dosage	Primary Mechanism
Thermodynamic (THI)	Methanol, MEG, DEG	High (10–60 wt%)	Lowers the freezing point, changes thermodynamics.
Low Dosage (LDHI)	Kinetic (KHI)	Low (<1–3 wt%)	Delays hydrate nucleation and growth.
Low Dosage (LDHI)	Anti-Agglomerant (AA)	Low (<1–3 wt%)	Prevents hydrate crystals from sticking together.

III.7 Limitations of Existing Approaches

Despite the range of available mitigation methods, no single strategy provides a universally satisfactory solution gas lift context. Thermodynamic inhibitors, while reliable, carry escalating costs and environmental concerns at the high concentrations required during severe winter conditions. Thermal methods are capital-intensive when deployed across a large well count. Mechanical pigging is reactive and causes production deferment. KHIs and AAs face technical constraints related to subcooling limits and liquid phase requirements respectively.

These limitations point toward the value of addressing the hydrate problem not solely through chemical or thermal treatment of the injection gas, but through a modification of the gas injection operating mode itself. The underlying cause of hydrate formation at wellheads is the sustained Joule-Thomson cooling of injection gas as it continuously passes through the choke valve under elevated pressure differentials.

Intermittent gas lift offers precisely this kind of operational alternative. Rather than maintaining a continuous injection of high-pressure gas, intermittent lift delivers gas in periodic, controlled cycles separated by shut-in periods during which the injection line is not exposed to cold flowing gas. This intermittent flow pattern limits the cumulative contact time between injection gas and water at sub-hydrate temperatures, reducing the probability of hydrate and plug formation without the need for continuous inhibitor injection.

CHAPTER IV

PRACTICAL PART



Chapter IV: Practical part

IV.1 Problematic

Numerous technical and operational challenges are associated with the gas lift process in oil wells, significantly impacting both production efficiency and the effective utilization of lift gas. Foremost among these challenges are the excessively high rates of gas injection and the formation of hydrates within the gas injection line.

Hydrate formation primarily occurs due to the sudden temperature drop triggered by the pressure reduction across the gas injection choke valves, a phenomenon described by the Joule–Thomson effect. When the lift gas is not properly dehydrated and contains free water, its passage through these valves causes rapid cooling. This process frequently results in hydrate crystallization, particularly during the winter months.

The Well Z09 is currently operating under continuous gas lift, with gas lift injected through the casing annulus to support production. According to the latest surface well test, the well produced a mere 8.35 Sm³/day of oil against a gas injection rate of approximately 5521 Sm³/day, indicating disproportionately high gas consumption relative to oil production. Furthermore, casing pressure and temperature data recorded during the night revealed average operating conditions of 28.32 bar and 6.02°C. Projecting these conditions onto the hydrate formation curve places the operating point firmly inside the hydrate stability region. This indicates an immediate risk of hydrate formation directly downstream of the choke valve in the gas injection line.

The primary concern is that under Continuous Gas Lift (CGL) operations, the injection rate must be continuously controlled via a choke valve. This creates a persistent pressure drop that induces Joule–Thomson cooling, reducing the gas temperature to conditions conducive to hydrate formation. Consequently, the core problem addressed in this study is whether transitioning from continuous to Intermittent Gas Lift (IGL) can mitigate the hydrate risk while enhancing overall gas lift efficiency.

To address this question, the study first evaluates the hydrate risk by comparing the casing pressure and temperature conditions against the established hydrate formation curve. Next, Well Z09 is modeled in PROSPER to assess its production performance under intermittent gas

lift conditions. The ultimate objective is to determine whether IGL can successfully shift the operating parameters outside the hydrate stability region while simultaneously improving oil production at a reduced gas injection rate.

IV.2 General Description of Well Z09

The oil well Z09 was drilled and completed in October 2008 in Tin Fouye Tabankort field. This well is currently producing using continuous gas lift. According to the most recent production test, conducted on 29 March 2026, this well produces 8.35 m³/d of oil without any reported water production and has a gas lift injection of approximately 5521 m³/d. The flowline pressure is estimated to be 5.3 bar, whereas casing pressure is estimated to be around 28 bar.

It can be seen from the completion schematic (Figure 0.1) that the well has a 2⁷/₈ in. tubing string and that gas lift mandrels have been used during completion. The packer has been placed at approximately 1127.07 m, while there is a lower liner down to about 1750 m in depth. Figure IV.1 illustrates the completion of well Z09.

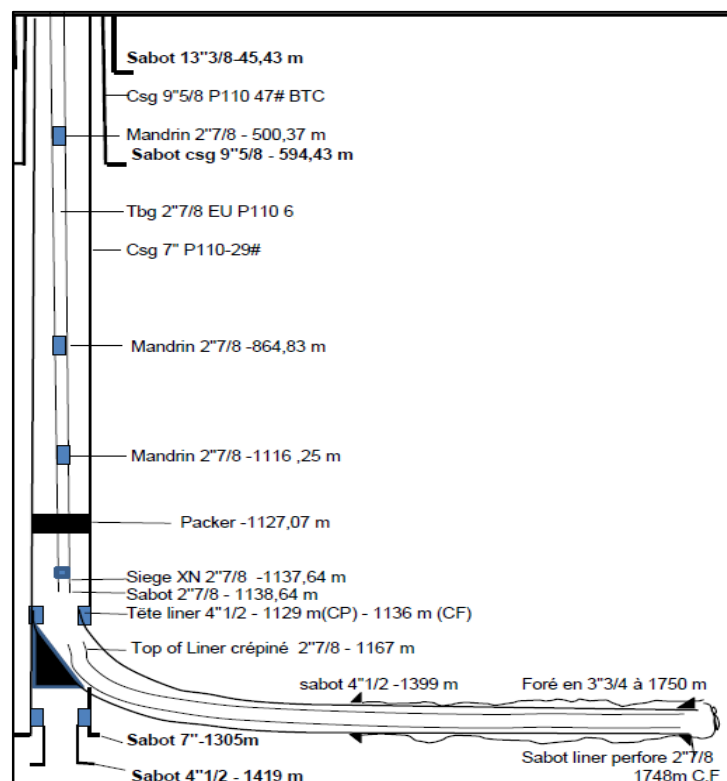


Figure 0.1: Z09 Well Completion.

GENERAL CONCLUSION



General conclusion

This study has successfully demonstrated that the transition from Continuous Gas Lift (CGL) to Intermittent Gas Lift (IGL) represents a viable strategy for optimizing well performance and mitigating hydrate formation risks in the Tin Fouye Tabankort (TFT) field. The thermodynamic evaluation of Well Z09 confirmed that existing CGL operations were inherently restricted by the Joule–Thomson effect. The analysis revealed that the pressure drop across the injection choke reduces the gas temperature to 6.02°C at 28.32 bar, placing the system firmly within the hydrate stability region.

Conversely, numerical modeling and simulation results indicated that the IGL scenario—which eliminates continuous throttling—shifts the operating point to 58 bar and 19.03°C, effectively repositioning the system into a hydrate-free zone and mitigating the risk of blockage. Beyond flow assurance, the IGL technique demonstrated a clear capacity to enhance production efficiency. Specifically, the simulation showed a marked increase in oil output from 8.35 Sm³/day to 11.4 Sm³/day, achieved while significantly reducing gas injection rates.

In conclusion, the findings suggest that the adoption of IGL is a high-potential operational improvement for wells in the TFT field facing hydrate-related challenges. Future field implementation trials are strongly recommended to validate these simulation-based results and to determine the broader scalability of the IGL technique across the entire field.

Recommendations

- ❖ Based on the results of this study, it is recommended to consider Intermittent Gas Lift as a practical alternative for well Z09, especially during cold periods when hydrate risk is higher. The IGL operating conditions should be carefully adjusted in the field to confirm the simulated performance and to ensure stable production.
- ❖ It is also recommended to monitor pressure and temperature continuously downstream of the choke valve and along the gas injection line. These measurements would help confirm the hydrate-risk zones identified in this study and improve the accuracy of future simulations.

- ❖ For better reliability, future work should include field validation of the calculated Joule–Thomson cooling effect and the estimated IGL temperature. Additional tests using real upstream and downstream temperature measurements across the choke valve would improve the accuracy of hydrate-risk prediction.

- ❖ Finally, the PROSPER model should be updated regularly using new well test data, gas composition, and operating conditions. This will make the model more representative of the real behavior of well Z09 and support better decisions regarding gas lift optimization and hydrate prevention.

- ❖ As a strategic enhancement to the existing flow assurance framework for Well Z09, it is recommended to Implementing a surface heat exchanger upstream of the injection choke is recommended to pre-heat injected gas and effectively counteract the temperature drops caused by the Joule–Thomson effect.

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APPENDIX



Appendix A: Joule–Thomson Calculation Details

Starting from the combined equation:

$$T_2 = T_1 - \frac{1}{C_p} \left[\frac{2a}{RT_1} - b \right] (P_1 - P_2)$$

Let:

$$\Delta P = P_1 - P_2$$

Then:

$$T_2 = T_1 - \frac{\Delta P}{C_p} \left[\frac{2a}{RT_1} - b \right]$$

Expanding the bracket:

$$T_2 = T_1 - \frac{2a\Delta P}{C_p RT_1} + \frac{b\Delta P}{C_p}$$

To remove T_1 from the denominator, multiply the whole equation by T_1 :

$$T_2 T_1 = T_1^2 - \frac{2a\Delta P}{C_p R} + \frac{b\Delta P}{C_p} T_1$$

Group the terms containing T_1 :

$$T_1^2 + \left(\frac{b\Delta P}{C_p} - T_2 \right) T_1 - \frac{2a\Delta P}{C_p R} = 0$$

This is a quadratic equation in T_1 :

$$AT_1^2 + BT_1 + C = 0$$

where:

$$\begin{aligned} A &= 1 \\ B &= \frac{b\Delta P}{C_p} - T_2 \\ C &= -\frac{2a\Delta P}{C_p R} \end{aligned}$$

Therefore, T_1 is obtained using the quadratic formula:

$$T_1 = \frac{-B + \sqrt{B^2 - 4AC}}{2A}$$

The positive root is selected because T_1 is an absolute temperature in Kelvin.

Substituting A , B , and C :

$$T_1 = \frac{-\left(\frac{b\Delta P}{C_p} - T_2\right) + \sqrt{\left(\frac{b\Delta P}{C_p} - T_2\right)^2 + \frac{8a\Delta P}{C_p R}}}{2}$$

Using:

$$\begin{aligned} T_2 &= 279.17 \text{ K} \\ \Delta P &= 2.968 \times 10^6 \text{ Pa} \\ a &= 0.313 \text{ Pa} \cdot \text{m}^6/\text{mol}^2 \\ b &= 5.07 \times 10^{-5} \text{ m}^3/\text{mol} \\ C_p &= 47.19 \text{ J/mol.K} \\ R &= 8.314 \text{ J/mol.K} \end{aligned}$$

we get:

$$T_1 = \frac{279.17 - \frac{(5.07 \times 10^{-5})(2.968 \times 10^6)}{47.19} + \sqrt{\left(\frac{(5.07 \times 10^{-5})(2.968 \times 10^6)}{47.19} - 279.17\right)^2 + \frac{8(0.313)(2.968 \times 10^6)}{(47.19)(8.314)}}}{2}$$

Using:

$$\begin{aligned} T_2 &= 279.17 \text{ K} \\ \Delta P &= 2.968 \times 10^6 \text{ Pa} \\ a &= 0.313 \text{ Pa} \cdot \text{m}^6/\text{mol}^2 \\ b &= 5.07 \times 10^{-5} \text{ m}^3/\text{mol} \\ C_p &= 47.19 \text{ J/mol.K} \\ R &= 8.314 \text{ J/mol.K} \end{aligned}$$

we get:

$$T_1 = \frac{279.17 - \frac{(5.07 \times 10^{-5})(2.968 \times 10^6)}{47.19} + \sqrt{\left(\frac{(5.07 \times 10^{-5})(2.968 \times 10^6)}{47.19} - 279.17\right)^2 + \frac{8(0.313)(2.968 \times 10^6)}{(47.19)(8.314)}}}{2}$$

First:

$$\frac{b\Delta P}{C_p} = \frac{(5.07 \times 10^{-5})(2.968 \times 10^6)}{47.19} \approx 3.19$$

and:

$$\frac{8a\Delta P}{C_p R} = \frac{8(0.313)(2.968 \times 10^6)}{(47.19)(8.314)} \approx 18940.6$$

Therefore:

$$T_1 = \frac{279.17 - 3.19 + \sqrt{(3.19 - 279.17)^2 + 18940.6}}{2}$$

$$T_1 = \frac{275.98 + 308.39}{2}$$

$$T_1 \approx 292.18 \text{ K}$$

Converting to Celsius:

$$T_1 = 292.18 - 273.15$$
$$\boxed{T_1 \approx 19.03^\circ \text{C}}$$

Appendix B: Field Measurements

Table 1: The recorded casing pressure and temperature.

Company: Field: Date: WELL	SONATRACH / DP - TFT				
	TFT				
	01/02/2026				
	Well Z09				
		Gauge SN		Gauge SN	
		W20115		W20132	
DATE	TIME	Casing Pressure	Casing Temperature	production Line Pressure	production Line Temperature
dd/mm/yy	hh:mm:ss	Bars(g)	C°	Bars(g)	C°
2/1/2026	9:13:46	28.0571	18.53	3.7292	24.51
2/1/2026	9:13:51	28.0595	18.53	3.7221	24.52
2/1/2026	9:13:56	28.0584	18.52	3.7053	24.53
2/1/2026	9:14:01	28.0561	18.52	3.7292	24.53
2/1/2026	9:14:06	28.0584	18.52	3.7172	24.54
2/1/2026	9:24:06	28.0571	18.53	3.7148	24.58
2/1/2026	9:34:06	28.4408	18.19	3.6768	24.45
2/1/2026	9:44:06	28.5434	18.58	3.6385	24.56
2/1/2026	9:54:06	28.0732	19.09	3.6832	24.95
2/1/2026	10:04:06	28.4479	19.59	3.5965	25.37
2/1/2026	10:14:06	28.5695	19.96	3.6008	25.72
2/1/2026	10:24:06	28.0812	20.67	3.6237	26.49
2/1/2026	10:34:06	28.3900	21.03	3.5367	26.96
2/1/2026	10:44:06	28.5271	20.63	3.4773	26.61
2/1/2026	10:54:06	28.1303	20.16	3.5784	26.29
2/1/2026	11:04:06	28.2697	20.46	3.5562	26.77
2/1/2026	11:14:06	28.6046	20.97	3.4668	27.17
2/1/2026	11:24:06	28.2296	20.34	3.5753	26.81
2/1/2026	11:34:06	28.2247	20.20	3.4579	26.69
2/1/2026	11:44:06	28.6048	20.33	3.4793	26.83
2/1/2026	11:54:06	28.3248	20.81	3.4858	27.33
2/1/2026	12:04:06	28.1723	21.37	3.4571	27.28
2/1/2026	12:14:06	28.5937	21.23	3.4160	27.41
2/1/2026	12:24:06	28.3984	21.92	3.5205	28.47
2/1/2026	12:34:06	28.1293	23.12	3.4354	29.20
2/1/2026	12:44:06	28.5684	23.42	3.3916	29.58
2/1/2026	12:54:06	28.4509	23.39	3.4835	29.41
2/1/2026	13:04:06	28.0797	23.31	3.4233	29.24
2/1/2026	13:14:06	28.5323	22.82	3.3710	28.66
2/1/2026	13:24:06	28.5186	22.93	3.3543	28.53
2/1/2026	13:34:06	28.0316	22.50	3.3237	28.03
2/1/2026	13:44:06	28.4699	22.83	3.3535	29.12
2/1/2026	13:54:06	28.5503	23.67	3.2423	29.33

2/1/2026	14:04:06	28.0942	23.88	3.3532	29.42
2/1/2026	14:14:06	28.4429	23.18	3.2721	28.73
2/1/2026	14:24:06	28.5711	22.80	3.3129	28.88
2/1/2026	14:34:06	28.0458	23.58	3.3262	29.72
2/1/2026	14:44:06	28.3660	23.58	3.2472	29.24
2/1/2026	14:54:06	28.5838	23.77	3.3096	29.53
2/1/2026	15:04:06	28.1117	23.27	3.3170	29.41
2/1/2026	15:14:06	28.3131	24.08	3.3330	30.15
2/1/2026	15:24:06	28.5858	23.45	3.2178	29.54
2/1/2026	15:34:06	28.1798	24.09	3.3859	30.45
2/1/2026	15:44:06	28.2298	23.70	3.2828	29.72
2/1/2026	15:54:06	28.5954	24.52	3.1968	30.85
2/1/2026	16:04:06	28.2998	24.12	3.3237	29.88
2/1/2026	16:14:06	28.1964	23.44	3.2352	29.21
2/1/2026	16:24:06	28.5685	23.22	3.2810	29.27
2/1/2026	16:34:06	28.3271	23.09	3.3002	29.29
2/1/2026	16:44:06	28.1300	23.35	3.3168	29.55
2/1/2026	16:54:06	28.5474	22.66	3.2332	28.95
2/1/2026	17:04:06	28.4180	22.32	3.2652	28.50
2/1/2026	17:14:06	28.0319	22.00	3.2660	28.04
2/1/2026	17:24:06	28.4641	21.36	3.1423	27.35
2/1/2026	17:34:06	28.5158	20.75	3.1865	26.90
2/1/2026	17:44:06	28.0486	19.99	3.2174	25.93
2/1/2026	17:54:06	28.4615	19.06	3.2008	24.87
2/1/2026	18:04:06	28.5626	18.03	3.1489	23.81
2/1/2026	18:14:06	28.0567	16.94	3.2447	22.82
2/1/2026	18:24:06	28.4032	16.10	3.2163	22.02
2/1/2026	18:34:06	28.5888	15.52	3.1233	21.48
2/1/2026	18:44:06	28.0532	14.96	3.3004	20.95
2/1/2026	18:54:06	28.3706	14.50	3.1623	20.50
2/1/2026	19:04:06	28.6056	14.02	3.1996	20.02
2/1/2026	19:14:06	28.0667	13.74	3.2478	19.77
2/1/2026	19:24:06	28.3421	13.45	3.2465	19.46
2/1/2026	19:34:06	28.6147	13.15	3.2618	19.17
2/1/2026	19:44:06	28.0980	12.76	3.3315	18.82
2/1/2026	19:54:06	28.3377	12.60	3.3555	18.70
2/1/2026	20:04:06	28.6061	12.35	3.2457	18.47
2/1/2026	20:14:06	28.1152	12.30	3.3401	18.41
2/1/2026	20:24:06	28.3149	12.30	3.2884	18.38
2/1/2026	20:34:06	28.6067	12.19	3.2254	18.25
2/1/2026	20:44:06	28.1384	11.99	3.3742	18.10
2/1/2026	20:54:06	28.3029	11.87	3.3418	17.97
2/1/2026	21:04:06	28.6144	11.61	3.3262	17.75
2/1/2026	21:14:06	28.1486	11.49	3.3363	17.58
2/1/2026	21:24:06	28.2715	11.11	3.4155	17.15
2/1/2026	21:34:06	28.5883	10.43	3.3084	16.38
2/1/2026	21:44:06	28.1814	10.14	3.4459	15.99
2/1/2026	21:54:06	28.2513	9.76	3.3940	15.55

2/1/2026	22:04:06	28.5890	9.32	3.3588	15.05
2/1/2026	22:14:06	28.2117	8.99	3.4932	14.77
2/1/2026	22:24:06	28.2293	8.84	3.3868	14.56
2/1/2026	22:34:06	28.5815	8.67	3.4063	14.37
2/1/2026	22:44:06	28.2455	8.40	3.4770	14.21
2/1/2026	22:54:06	28.2268	8.16	3.4313	14.01
2/1/2026	23:04:06	28.5692	8.04	3.3854	13.86
2/1/2026	23:14:06	28.2309	7.93	3.4956	13.71
2/1/2026	23:24:06	28.2388	7.95	3.4978	13.72
2/1/2026	23:34:06	28.4381	7.74	3.3848	13.51
2/1/2026	23:44:06	28.2511	7.62	3.4297	13.36
2/1/2026	23:54:06	28.1267	7.46	3.4193	13.11

2/2/2026	0:24:06	28.1528	7.05	3.5345	12.84
2/2/2026	0:34:06	28.5375	6.81	3.5168	12.65
2/2/2026	0:44:06	28.2975	6.73	3.5473	12.60
2/2/2026	0:54:06	28.1974	6.90	3.5836	12.77
2/2/2026	1:04:06	28.5586	7.10	3.4573	12.95
2/2/2026	1:14:06	28.2800	6.94	3.5975	12.79
2/2/2026	1:24:06	28.1895	6.85	3.6004	12.66
2/2/2026	1:34:06	28.5616	6.66	3.5946	12.40
2/2/2026	1:44:06	28.2504	6.51	3.5956	12.19
2/2/2026	1:54:06	28.1728	6.31	3.5201	11.97
2/2/2026	2:04:06	28.5645	6.20	3.5616	12.02
2/2/2026	2:14:06	28.2455	6.14	3.5484	11.87
2/2/2026	2:24:06	28.1606	6.18	3.5552	11.91
2/2/2026	2:34:06	28.5534	6.06	3.5115	11.84
2/2/2026	2:44:06	28.2595	5.95	3.6790	11.72
2/2/2026	2:54:06	28.1774	5.74	3.5617	11.53
2/2/2026	3:04:06	28.5642	5.58	3.5070	11.35
2/2/2026	3:14:06	28.2302	5.33	3.6537	11.17
2/2/2026	3:24:06	28.1884	5.32	3.5360	11.12
2/2/2026	3:34:06	28.4721	5.17	3.5553	10.95
2/2/2026	3:44:06	28.2801	5.19	3.5226	11.01
2/2/2026	3:54:06	28.0930	5.06	3.6089	10.87
2/2/2026	4:04:06	28.5648	5.00	3.5306	10.80
2/2/2026	4:14:06	28.3582	5.04	3.6089	10.89
2/2/2026	4:24:06	28.1120	5.13	3.6709	10.97
2/2/2026	4:34:06	28.5286	5.14	3.5922	10.98
2/2/2026	4:44:06	28.3279	4.97	3.6833	10.80
2/2/2026	4:54:06	28.1271	4.98	3.6049	10.75
2/2/2026	5:04:06	28.5345	5.00	3.6379	10.64
2/2/2026	5:14:06	28.2783	5.03	3.6067	10.86
2/2/2026	5:24:06	28.1619	5.06	3.6738	10.86
2/2/2026	5:34:06	28.5346	5.02	3.6087	10.46
2/2/2026	5:44:06	28.2383	4.99	3.6553	10.39

2/2/2026	5:54:06	28.1963	5.01	3.6409	10.49
2/2/2026	6:04:06	28.5505	4.98	3.6020	10.41
2/2/2026	6:14:06	28.2080	4.97	3.6884	10.23
2/2/2026	6:24:06	28.2108	4.97	3.6488	9.84
2/2/2026	6:34:06	28.5645	4.97	3.6521	9.65
2/2/2026	6:44:06	28.1772	4.98	3.6766	9.83
2/2/2026	6:54:06	28.2173	5.00	3.6174	10.12
2/2/2026	7:04:06	28.5552	5.05	3.5827	10.13
2/2/2026	7:14:06	28.1542	5.12	3.6960	10.09
2/2/2026	7:24:06	28.2611	5.25	3.7392	10.24
2/2/2026	7:34:06	28.5393	5.40	3.6554	10.36
2/2/2026	7:44:06	28.1182	5.65	3.7387	10.83
2/2/2026	7:54:06	28.3086	5.69	3.6651	11.71
2/2/2026	8:04:06	28.5626	6.70	3.6817	12.65
2/2/2026	8:14:06	28.0930	7.69	3.7241	13.63
2/2/2026	8:24:06	28.3254	8.68	3.7016	14.59
2/2/2026	8:34:06	28.5482	9.66	3.7004	15.54
2/2/2026	8:44:06	28.0629	10.66	3.7342	16.56
2/2/2026	8:54:06	28.3418	11.58	3.7339	17.39

Date of Test	Choke	OIL (m3/d)	Diff Oil	WATER (m3/d)	GAS (m3/d)	Diff Gas	Gas-Lift (m3/d)	GOR (m3/m3)	GLR (m3/m3)	Wcut %	P-WH/ P-P (Bar)	P-Csg (Bar)	Natu
2026-03-29	32	8.35	0	0			5521	0.00	0.00	0.00	5.3/3.9	46.0	-
2025-11-02	108	14.44	0	0			9646	0.00	0.00	0.00	3.8/3.6	40.0	-
2025-05-11	108	9.5	0	0			5703	0.00	0.00	0.00	3.7/3.3	29.0	-
2024-12-06	108	19.2	0	0			9499	0.00	0.00	0.00	4.1/3.6	0.0	-
2024-11-25	108	28.8	0	10828			0	375.97	375.97	0.00	2.4/2.0	0.0	-
2022-07-04	0	7.1	34.9	0			9965	0.00	0.00	83.10	0.0/0.0	0.0	-
2022-01-14	0	0	0	0			0	0	0	100	0.0/0.0	0.0	-
2021-06-29	0	21.7	1.9	0			13764	0.00	0.00	8.05	0.0/0.0	0.0	-
2020-10-22	0	14.6	8.9	0			9940	0.00	0.00	37.87	0.0/0.0	0.0	-
2019-09-09	0	12.4	22.3	0			8180	0.00	0.00	64.27	0.0/0.0	0.0	-
2019-06-19	0	21.2	26.5	0			11615	0.00	0.00	55.56	0.0/0.0	0.0	-
2018-05-22	0	28.1	1	0			10160	0.00	0.00	3.44	0.0/0.0	0.0	-
2017-07-08	0	17.5	25.9	0			11440	0.00	0.00	59.68	0.0/0.0	0.0	-
2017-07-07	0	16.6	10.7	0			9010	0.00	0.00	39.19	0.0/0.0	0.0	-
2016-10-28	0	19.1	19.5	0			12950	0.00	0.00	50.52	0.0/0.0	0.0	-
2016-06-26	0	26.5	22	0			7380	0.00	0.00	45.36	0.0/0.0	0.0	-
2016-06-07	0	25.6	19.5	0			7860	0.00	0.00	43.24	0.0/0.0	0.0	-
2016-03-15	0	66	6.6	0			12640	0.00	0.00	9.09	0.0/0.0	0.0	-

Figure 1: Historical Production Data of Well Z09