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-THÈME-

Identification, Prediction and Solving Liquid Loading Problems in Gas Condensate Wells of Hassi R'mel Field

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Abstract

This work gives all the important background information of the liquid loading topic itself and summarizes the most common artificial lift methods. Using Pipesim software, the primary objective of this study is to identify and to predict when the onset of the liquid loading will occur by comparing the flow rate obtained from Nodal Analysis and the critical rate obtained from Turner et al. correlation. Furthermore, this study aims to solve the liquid loading problem by application of the velocity string and boosting. The results obtained show that two wells from the four studied wells are loading up. While for the other two wells, the liquid loading is predicted in 2021 and 2022. The results also show that the liquid loading is inevitable and not always obvious in gas wells when it occurs; if a well is loaded, it still may produce for a long time before his shut-in. The results further show that the use of velocity string works to delay the occurrence of the liquid loading but does not solve it finally; it is a short-term solution. Also, boosting lowers the wellhead pressure and allowing liquids to be unloaded from the well. Therefore, it could keep the well free of liquids for a long time.

Keywords: Liquid Loading; Hassi R’mel Gas Field; Gas Wells; Critical Velocity; Nodal Analysis; Turner et al. model; Prediction; Artificial lift

Résumé

Ce travail donne toutes les informations importantes sur le sujet du chargement de liquide lui-même et résume les méthodes artificielles pour résoudre ce problème. En utilisant le logiciel Pipesim, l'objectif principal de cette étude est d'identifier et de prédire le début de chargement de liquide dans le puits en comparant le débit obtenu à partir de l'analyse nodale et le débit critique obtenu à partir de la corrélation de Turner et al. De plus, cette étude vise à résoudre ce problème par l'application de la velocity string et le boosting. Les résultats obtenus montrent que deux puits parmi les quatre puits étudiés se chargent. Alors que pour les deux autres puits, le chargement de liquide est prévu en 2021 et 2022. Les résultats montrent également que le chargement de liquide est inévitable et pas toujours évident dans les puits de gaz lorsqu'il se produit; si un puits est chargé, il peut encore se produire longtemps avant sa fermeture. Les résultats montrent en outre que l'utilisation de velocity string fonctionne pour retarder l'apparition de chargement de liquide mais ne le résout pas finalement; c'est une solution à court terme. De plus, le boosting abaisse la pression de tête de puits et permet aux liquides

d'être déchargés du puits. Par conséquent, il pourrait garder le puits exempt de liquides pendant longtemps.

Mots-clés: Chargement de Liquide; Champ de Gaz Hassi R'mel; Puits de Gaz; Vitesse Critique; Analyse Nodale; Turner et al. Modèle; Prédiction; Méthodes Artificielles

ملخص

يقدم هذا العمل المعلومات الأساسية لموضوع تحميل السائل في آبار الغاز و يلخص طرق الرفع الاصطناعية الأكثر شيوعًا. باستخدام برنامج Pipesim، يتمثل الهدف الأساسي لهذه الدراسة في تحديد وتوقع موعد بدء تحميل السائل من خلال مقارنة التدفق الذي تم الحصول عليه من Analyse Nodale و التدفق الذي تم الحصول عليه من Turner et al. علاوة على ذلك، تهدف هذه الدراسة إلى حل مشكلة تحميل السائل عن طريق تطبيق Velocity String و Boosting. أظهرت النتائج التي تم الحصول عليها أنه يتم تحميل بئرين من الآبار الأربعة المدروسة. بينما بالنسبة للبئرين الأخريين ، من المتوقع تحميل السائل في عامي 2021 و 2022. تظهر النتائج أيضًا أن تحميل السائل أمر لا مفر منه وليس واضحًا دائمًا في آبار الغاز عند حدوثه؛ إذا تم تحميل بئر، فقد يستمر إنتاجه لفترة طويلة قبل إقفاله. تظهر النتائج كذلك أن استخدام Velocity String يعمل على تأخير حدوث تحميل السائل ولكنه لا يحلها في النهاية؛ إنه حل قصير الأمد. كما أن Boosting يخفض ضغط فوهة البئر ويسمح بتفريغ السوائل من البئر. لذلك، يمكن أن تحافظ على البئر خاليًا من السوائل لفترة طويلة.

كلمات مفتاحية: تحميل السائل، حقل غاز حاسي الرمل، آبار الغاز، السرعة الحرجة، Analyse Nodale، Turner et al، تنبؤ؛ طرق اصطناعية

Nomenclature

GOC: Gas Oil Contact (m)

GWC: Gas Water Contact (m)

P_r: Reservoir Pressure (bar)

T_r: Reservoir Temperature (C°)

P_{wh}: Wellhead Pressure (bar)

P_{wf}: Flowing Bottom Hole Pressure (bar)

K: formation permeability (md)

h: formation thickness (ft)

Z: gas compressibility factor

μ_g: gas viscosity (cp)

r_e: drainage radius (ft)

r_w: wellbore radius (ft)

GOR: Gas Oil Ratio (sm^3/sm^3)

LGR: Liquid Gas Ratio ($sm^3/MMsm^3$)

WGR: Water Gas Ratio ($sm^3/MMsm^3$)

Wcut: Water Cut (%)

Q_g: Gas Flow Rate (Msm3/d)

Q_{cg}: Critical Gas Rate (Msm3/d)

FMV: Fluid Mean Velocity (m/s)

LLV: Liquid Loading Velocity (m/s)

LLVR: Liquid Loading Velocity Ratio

LLVRm: Liquid Loading Velocity Ratio maximum

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Introduction

In producing gas condensate wells, the gas phase hydrocarbons produced from underground reservoirs will have liquids phase associated with them. Liquids come from multiple sources, including formation water, condensate oil/water, and interstitial water. Formation water invading the wellbore is the most common source. The accumulation of liquids that are co-produced with gas at the bottom of the well during gas production when the transport energy can no longer transport it to the surface is called liquid loading.

Liquid loading is one of the major challenging issues facing gas wells. And the main cause of this phenomenon is that in the later period during the gas well production, the reservoir pressure is depleted, and the produced gas flow rate decreases until the gas reaches a critical condition at which time the liquid loading is initiated. At the inception of liquid loading, the gas flow rate is not enough to carry the associate liquids completely to the surface and the liquids start to accumulate at the bottom of the well. Then, the liquid loading will create increased back-pressure on the formation and reduce production pressure differential, which decreases the gas rate and even kills the gas well. In order to reduce the effect of liquid loading on gas production, loading problems should be diagnosed in time and dealt properly and efficiently. Therefore, accurate identification and prediction of liquid loading in the well are very important since these will allow taking the necessary measures and design the proper solution to avoid liquid loading and extend the well production life. For this reason, many remedial lifting options have been developed to conquer this challenge; some unloading solutions rely on the existing natural energy of the system, while others provide extra energy to bring the liquids to surface.

Lately, this current problem is one of the most challenges in Hassi R'mel gas condensate wells. The probability of liquid loading in this field due to its high water production, specific reservoir conditions, and large production 7" ID string is very important and needs to be one of the most essential researches.

This study deals with the identification and prediction of the liquid loading problems in the gas condensate wells of the Hassi R'mel field and the different methods to prevent or remove this problem in order to maintain the production rate and extend the life of the well.

The objectives of this study are as follows:

- To identify the liquid loading problems in gas wells;

- To identify the different symptoms of liquid loading problems;
- To simulate the gas well production performance under liquid loading conditions;
- To use the Pipesim software to identify and predict the liquid loading onset with the method of Turner;
- To solve this problem after predict it by using velocity string and boosting.

This work has been divided into four chapters starts with a brief introduction represents our study. The first chapter provides details of the liquid loading concepts in the gas wells. It also describes a presentation of the Hassi R'mel field and the major symptoms to identify the liquid loading in the gas condensate wells of the Hassi R'mel field. Chapter two represents the different steps to create the model and the current performance of wells using Pipesim software. In chapter three, we make a prediction calculation of the onset for liquid loading in Hassi R'mel gas wells using the Turner method. In chapter four, we represent a theoretical background of the different methods of handling liquid loading in gas wells, and then we apply the methods of velocity string and the compression to solve this problem in the gas wells of the Hassi R'mel gas field. Lastly we finish by a conclusion and we put our future recommendations.

Methodology

By using the Pipesim software, the well model will be created.

By using the Pipesim software, the current production performance of the well will be simulated.

By using the Pipesim software, the Turner critical flow rate and critical velocity will be calculated.

By using the Pipesim software, the onset of the liquid loading will be identified or predicted.

By using the Pipesim software, the velocity string will be applied to solve the liquid loading problem.

By using the Pipesim software, boosting will be applied to solve the liquid loading problem.

Chapter 1

Liquid Loading Problems in Hassi R'mel Gas Condensate Wells

1. Liquid Loading Concepts in Gas Wells
2. Overview on Hassi R'mel Field
3. Liquid Loading Problem in Hassi R'mel Gas Field

Preface

Natural gas production is faced with a variety of challenges one of which is the issue of liquid loading. Liquid loading refers to the accumulation of liquids (e.g. water and/or condensate) from different sources in the wellbore; it takes place when the gas rate is not high enough to lift liquids to the surface. To understand this problem, we touch in this chapter general concepts of liquid loading, and then we take a look at this problem in the Hassi R'mel field.

1.1. Liquid Loading Concepts in Gas Wells

The concepts of the liquid loading in gas wells based on the understanding of the sources of liquids, the different multiphase flows, and the indicators of the liquid loading.

1.1.1. What is Liquid Loading of Gas Condensate Well?

When a gas well is producing, the pressure in the gas reservoir is high and the gas velocity in the tubing is sufficient to lift the liquids that are produced with the gas upwards to the surface. However, after several years, towards the end of field life, the pressure in the reservoir will become so low that the gas does not meet the critical velocity necessary to transport all produced liquids to the surface. [21] Under this condition, the produced liquids will accumulate in the wellbore, imposing additional backpressure (high hydrostatic pressure in the well) against the formation that can significantly affect the production capacity of the well. [5] The accumulation of liquids leads to reduce the production and shortening of the time until the well no longer will produce (the well kills itself). [13] So, the liquid loading of a gas well is the inability of the produced gas to remove the co-produced liquids from the wellbore.

1.1.2. Multiphase Flow

To understand the effects of liquids in the gas well, it is important to understand how liquid and gas behave when flowing together upwards in the production string of the well. Multiphase flow in a vertical conduit is usually represented by four basic flow regimes as shown in **figure (1.1)**. At any given time in well's history, one or more of these regimes will be present. A flow regime is determined by the velocity of the gas and liquid phases and the relative amounts of gas and liquid at any given point in the flow stream. [18]

- **Annular/Mist Flow:** It occurs at high gas velocity, in which the gas is the continuous phase and the liquid is present in dispersed droplets (mist) in the gas and a thin film (annular) at the wall of the pipe. [5]
- **Transition Flow:** When gas velocity is decreased, the flow starts to change from mist to slug therefore the continuous phase changes from a gas to a liquid, and liquid may still be in gas as mist form. [14] So instead of moving upwards the liquid film reaches a certain point where it starts to move downwards, liquid loading is related to this transition.
- **Slug Flow:** As the gas rate decreases even further, the gas appears as large slugs in liquid but the continuous phase is liquid. [3]
- **Bubble Flow:** At last lower gas flow rates, bubbly flow occurs; where the tubing is almost filled with liquid (continuous phase). Free gas is present as small bubbles, rising in the liquid. [5]

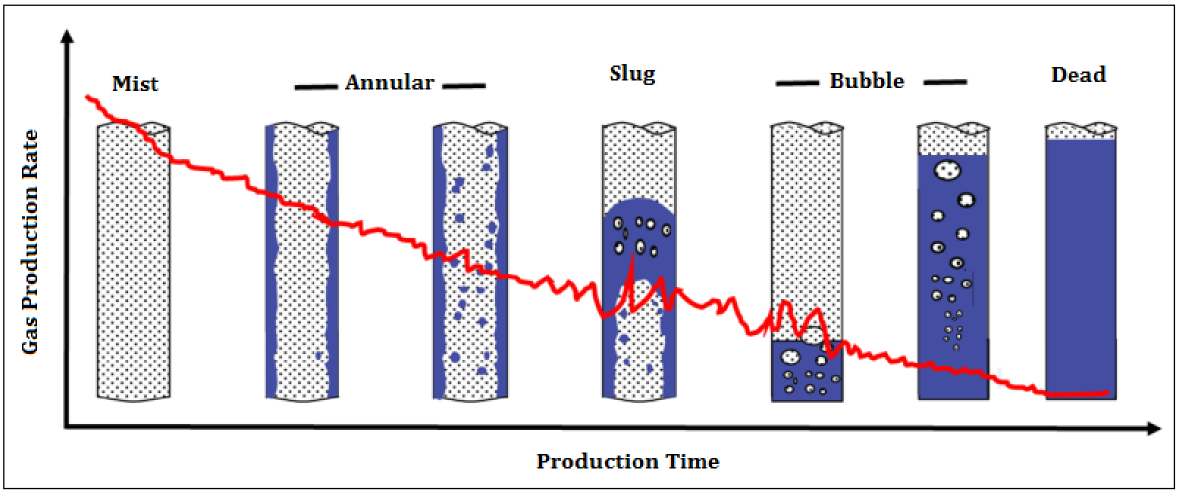

Figure (1.1): Gas Well Loading Flow Regimes [24]

A gas well may go through any or all of these flow regimes during the life of the well. It may initially have a high gas velocity so that the flow regime is in mist flow in the tubing but maybe in a bubble, transition, or slug flow below the tubing end to the mid-perforations. As time increases and production declines, the flow regimes from perforations to the surface will change as the gas velocity decreases. Liquid production may also increase as gas production declines.

1.1.3. Sources of Liquids in Producing Gas Well

Many gas wells produce not only gas but also liquids. These liquids may be free water, water condensate, and/or hydrocarbon condensate. If the reservoir pressure has decreased below the dew point, condensate is produced with the gas as a liquid; if the reservoir pressure is above the dew point, the condensate enters the wellbore in the vapor phase with the gas and drops out as a liquid in the tubing or separator when the pressure drops. Produced liquids along with gas may have several sources depending on the conditions and types of the reservoir from which gas is produced: [22]

- **Water Coning:** If the gas rate of the well is high enough, this may result in high decline pressure enough to pull water production from an underlying zone, even if the perforations do not extend to the underlying zone. Horizontal wells generally reduce water coning effects. [10]
- **Aquifer Water:** The aquifer giving pressure support to produced gas will eventually reach the perforations and enters the wellbore, giving rise to liquid loading. [10]
- **Free Water Formation:** Water can enter the well through the perforations with the produced gas. This can be a result of thin layers of gas and liquid. [3]
- **Water Production from another Zone:** It is possible to produce liquids from another zone, either with an open-hole completion or in a well having several sections perforated. [10]
- **The water of Condensation:** Natural gas present in the reservoir may be saturated if the conditions are suitable for the water to dissolve in it. In this case, water will enter the well as vapor dissolved in natural gas and there will be no or very little water in the liquid phase at the bottom, near the perforations. As the solution flows through the production string the water will start condensing if the temperature and pressure conditions in the well drop below the dew point. [13] Eventually, the condensed water will accumulate at the bottom of the well.
- **Hydrocarbon Condensates:** Like water, hydrocarbons can also enter the well with the produced gas in the vapor phase. As the gas solution flows to the surface, vapor state hydrocarbons may start condensing when conditions drop below the dew point and eventually start loading up the well just like water. [13]

1.1.4. Symptoms of Liquid Loading in Gas Wells

Liquid loading is not always obvious and the recognizing of liquid loading problem is not an easy task. Hence, the use of diagnostic tools to discover its occurrence could be very useful in preventing or delaying its occurrence. Examples of diagnostic tools that could be deployed include: [1]

- Numerical or analytical models to predict the critical rate;
- Use well performance plots;
- Use the production logging tool (PLT);
- Monitoring the casing and tubing head pressure with time;
- Plots of gas production rate with time;
- Making pressure gradient plots.

Among the previous indicators, the most useful symptoms indicating liquid loading include the following:

- **Erratic production and Increase in Decline rate:** An important indication of down-hole liquid loading problems is the shape of a production decline curve. The decline curve should be analyzed over time, looking for changes in the general trend. [5] This is explained by **Figure (1.2)**; the smooth exponential type decline curve represents a normal gas production considering reservoir depletion, while the sharply fluctuating curve is indicative of liquid loading.

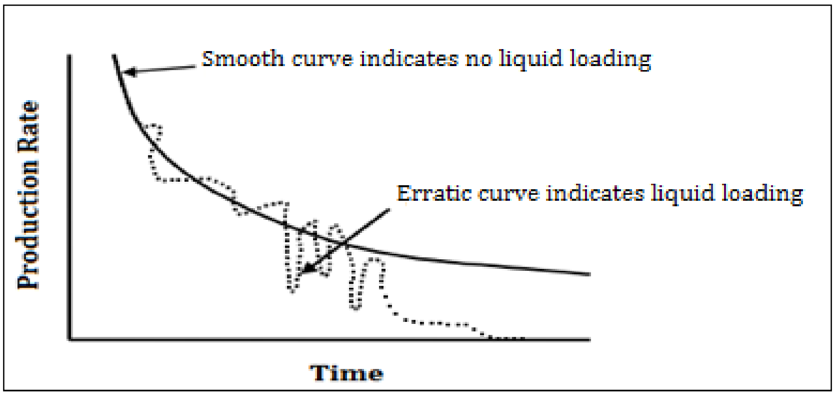

Figure (1.2): Decline Curve showing Liquid Loading [11]

- **Pressure Survey showing Tubing Liquid Level:** Flowing or static well pressure surveys are perhaps the most accurate method available to determine the liquid level in a gas well. [5] The measured pressure gradient is a direct function of the density of the medium and the depth; and for a single static fluid, as shown in **figure (1.3)**; the pressure with depth should be nearly linear. Since the density of the gas is significantly lower than that of water or condensate, the measured gradient curve will exhibit a sharp change of slope when the standing liquid in the tubing is encountered.

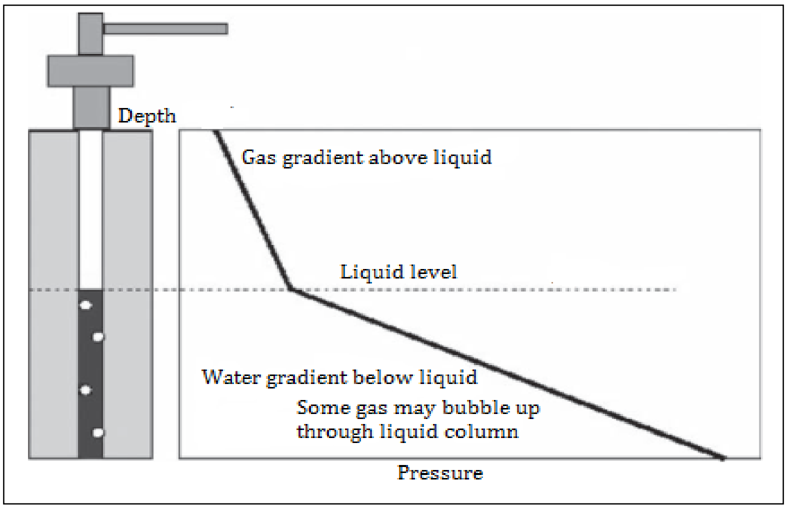

Figure (1.3): Pressure Survey showing Liquid Level [13]

- **Liquid Production Ceases:** Some high rate gas wells readily produce liquids for a time and then drop off too much lower rates. As gas production declines, liquid production can cease. In these cases, the well is producing gas at rates below the critical rate that can transport the liquids to the surface. [13] The result is that the liquids continue to accumulate in the wellbore and the gas bubbles through the accumulated liquids.

1.2. Overview on Hassi R'mel Field

Before studying the problem of liquid loading in Hassi R'mel gas wells, this section represents an overview of the Hassi R'mel gas field.

1.2.1. Presentation of Hassi R'mel Field

Algeria's largest natural gas field, Hassi R'mel, is located in the center of the country to the northwest of Hassi Messaoud, approximately 535 km south of the capital Algiers, at an altitude of about 760 m. It extends 80 km from north to south, 50 km from east to west; and it covers an area of 3200 km^2.

The giant Hassi R'mel gas field is one of the largest gas fields in the world; it holds proved reserves of about 85 trillion cubic feet, more than half of Algeria's total proved natural gas reserves. It was discovered in 1956 by the drilling of HR001 and came on production in 1961. The field is a gas condensate reservoir with an oil rim on the eastern flank, which was discovered in 1979.

The Hassi R'mel gas field is developed by three production zones (north, center, and south) separated by two gas re-injection zones as shown in **figure (1.4)**: [4]

- **North Zone:** It consists of the North Gas Treatment Module MPP3 (Module Processing Plant), the North Boosting Station (SBN), and the North Compression Station (SCN).
- **Central Zone:** It consists of the Central Gas Treatment Modules MPP0, MPP1, and MPP4, the Central Boosting Station (SBC), the Associated Gas Recovery Station (SRGA), the National Gas Dispatching Center (CNDG), and the Storage and Transfer Center (CSTF).
- **South Zone:** It consists of the South Gas Treatment Module MPP2, the South Boosting Station (SBS), the South Compression Station (SCS), the Djebel Bissa Gas Treatment Center (CTG-DJB) and the South Gas Treatment Center (CTG-Sud).

The Hassi R'mel Oil rim is developed by four Oil Treatment Centers (CTH1, CTH2, CTH3, and CTH4) and CTH-Sud for Hassi R'mel Oil South as shown in **figure (1.4)**.

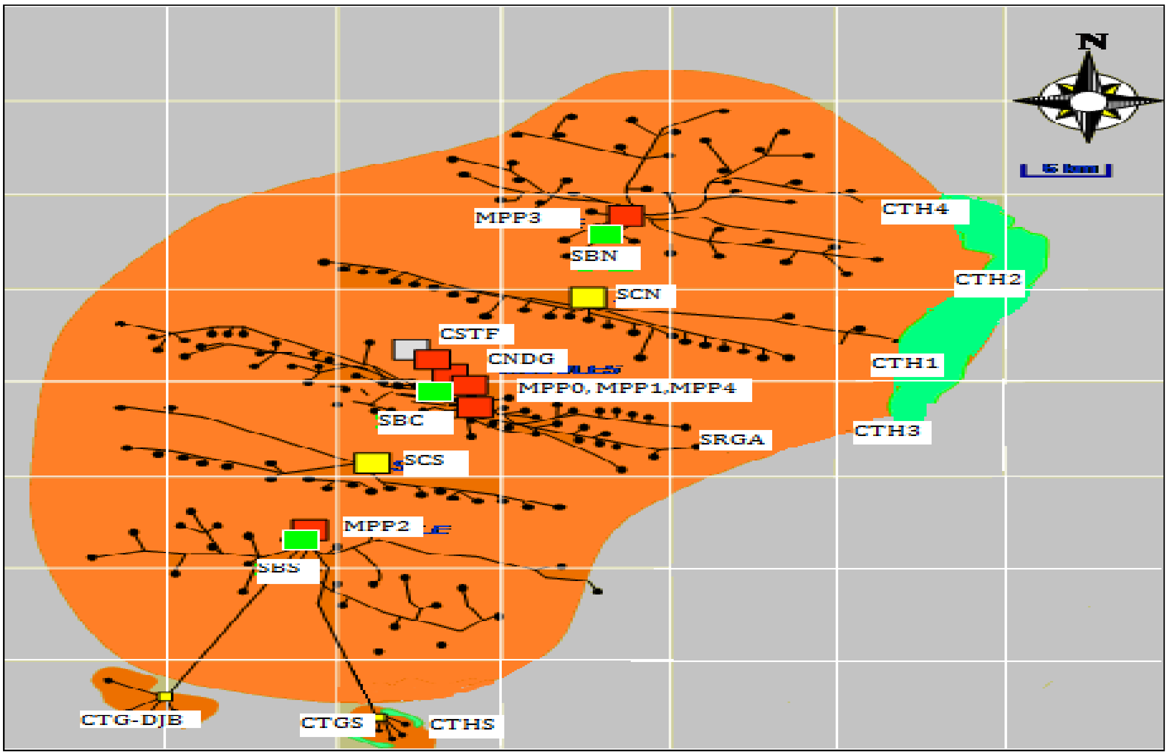

Figure (1.4): Hassi R'mel Field Organization [4]

1.2.2. The Geological Structure of Hassi R'mel Gas Field

The structure of the field is an anticline with a dip of 0.56°, on the order of 10 m/km, following the north-west direction. The main producing reservoir is the Upper Clay-Sandstone

Triassic (TAGS) which is at an average depth of 2200 m; it is made up of three reservoir levels (A, B, and C) as shown in **table (1.1)**.

Table (1.1): Hassi R'mel Gas Reservoir "Triassic" Levels [4]

Reservoir Levels	A	B	C
Facies	Fine Sandstone	Medium to Fine Sandstone	Medium to Coarse Grain with Quartz
Average Thickness (m)	11 to 34	0 to 25	0 to 60
Average Permeability (md)	250	200	800
Average Porosity (%)	16	15	16
Average Initial Water Saturation (%)	18.5	20.5	16.5

1.2.3. Reservoir Characteristics and In-Situ Fluids of Hassi R'mel Gas Field

The main characteristics of the reservoir and the in-situ fluids in Hassi R'mel field are shown in **table (1.2)**.

Table (1.2): Reservoir Characteristics and In-Situ Fluids of Hassi R'mel Gas Field [9]

Regional Contacts	**Gas / Oil Contact**	**-1487 m**
	Gas / Water Contact	-1500 m
Initial Conditions	Reservoir Pressure	311.1 (kgf/cm^2)
	Reservoir Temperature	90 C°
	Reference Depth	-1450 m
	Dew Point Pressure	311.1 (kgf/cm^2)
Gas Condensate	Initial Volume Factor	0.004022(rm^3/sm^3)
	Initial Compressibility Factor	0.9603
	Condensate Richness	210 (g/l)
	GPL Richness	94 (g/l)
	Condensate Density	68 API°
	Raw Gas Density	0.2457 (g/cm^3)
Formation Water	Density	1.155 (g/cm^3)
	Salinity	330 (g/l)

1.2.4. Encountered Problems during Hassi R'mel Gas Field Exploitation

Among the major problems related to gas production in the Hassi R'mel field, is the water influx (producing water along with gas). The inflow saturated salt water is coming from the formation (natural aquifer). This co-production of water can cause many problems such as corrosion, gas hydrate formation, and scale/salt deposition. [9]

As the salinity is high, the salt remains emulsified with the condensate before final treatment, this represents a risk of damage to the gas treatment installations. This problem (high salinity) is one of the major reasons to close the wells. [9]

Another production constraint is the dry gas breakthrough (recovery of the re-injected gas at the producer wells); this phenomenon has appeared on certain producer wells which are close to the injector gas wells.

1.2.5. Current State of Hassi R'mel's Gas Wells

Currently, the average daily production of gas in the Hassi R'mel field is about 182 ($MMsm^3/d$). This production is ensured by 206 producer wells; 53 wells in the north zone, 100 wells in the center zone, and 53 wells in the south zone. Moreover, there are 5 closed wells for high salinity and 3 closed wells for technical problems. [17]

The average daily re-injection of dry gas in the Hassi R'mel field is about 42 ($MMsm^3/d$). It is ensured by 57 injector wells; 29 wells in the north zone and 28 wells in the south zone. [17]

1.3. Liquid Loading Problem in Hassi R'mel Gas Field

This section represents the different symptoms to identify the occurrence of the liquid loading in some gas wells of Hassi R'mel field.

1.3.1. Water Production of Hassi R'mel's Gas Wells

As we mentioned before, there are different sources for water co-producer with gas. The main sources of producer water in the gas wells of the Hassi R'mel field are the condensate water, water coning, and the saltwater of the formation (brine). The water influx from the formation is caused by:

- The vicinity of the aquifer (GWC) to the producer reservoir (as shown in **table (1.3)**, some example wells).

- The reservoir has good petro-physical characteristics which facilitate the drainage of water to the reservoir.
- The reservoir has natural fractures which facilitate the drainage of water to the reservoir.

In traditional gas wells, produced water is brought to the surface along with the gas. **Figure (1.5)** shows the evolution of producer free water which is represented by water gas ratio (WGR) for the different zones of the Hassi R'mel field.

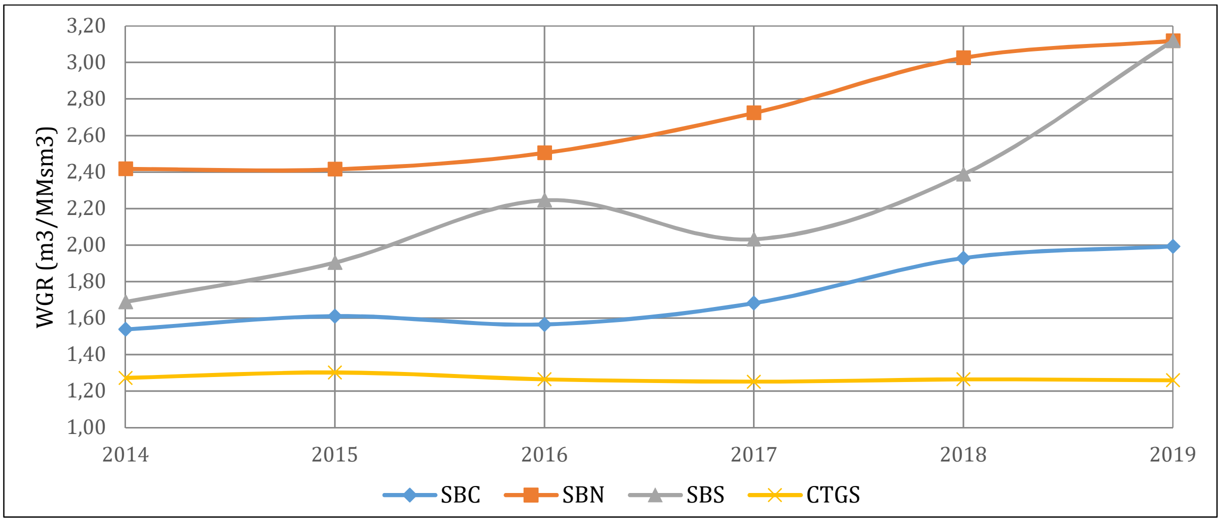

Figure (1.5): Evolution of WGR in Hassi R'mel Field [9]

1.3.2. The Last Measurements of GWC in Hassi R'mel field

From the **table (1.3)** and comparing with the initial GWC assumed at -1500 m, we notice that the GWC rid up in the different reservoir levels and the different zones.

Table (1.3): The Measurement of GWC in Hassi R'mel Field [9]

Well	Zone	Date	GWC (m)	Reservoir level	Top (m)	Bottom (m)
HR007	Central	2019	-1419.5	A	-1404	-1427
HR055	Central	2019	-1445	C	-1410.85	-1450.85
HR104	North	2016	-1458.7	C	-1460.5	-1508.8
HR112	North	2019	-1435	B	-1429.82	-1439.82
HR113	North	2019	-1443	B	-1437.31	-1450.81
HRD001	South	2018	-1403	C	-1398.5	-1408.5
HRD003	South	2018	-1439.3	C	-1432.8	-1439.8
HRD023	South	2018	-1475	C	-1459.81	-1474.81

1.3.3. Identification of Liquid Loading in Hassi R'mel's Gas Wells

The problem of liquid loading in Hassi R'mel's gas well is due to the accumulation of hydrocarbon condensates, water condensate, and free salt water in the wellbore. This problem occurred recently in Hassi R'mel's gas wells; after the decline of the reservoir pressure, the velocity of the fluid in the tubing decreases. Eventually, the gas velocity up the production tubing is no longer sufficient to fully carry the co-produced liquids to the surface. The liquid loading will not always lead to non-production. If a well is loaded, it still may produce for a long time. If liquid loading is recognized and reduced, higher producing rates are achieved.

As we discussed before, there are several methods used to identify the onset of liquid loading in gas wells; based on field experience, the problem of liquid loading in Hassi R'mel's gas wells is proved by the following points: [9]

- Following the results of RPM or RST logging, the water gas contact is increasing in the reservoir C (the GWC is assumed with a Sw cut-off at 60%).
- Following the results of well testing, some wells in the Hassi R'mel field, especially in the south zone, are producing water with high salinity; this results in the closure of these wells.
- Based on the results of logging tools that are used to locate the water entry point, proper unwanted water shut off method is used. Bridge plug is installed to isolate the water production area.
- The most important sign of liquid loading in Hassi R'mel's gas well is the lower production rate, called the meta-stable rate, a term introduced by Van Gool and Currie (2007) [2], at which the well still produces, even though liquid loading is occurring. Before liquid loading, the well produces at a stable rate. As liquid loading starts, there exists a meta-stable rate at which the production rate is less and the tubing head pressure decreases.
- After the detection of the meta-stable gas flow, the well is shut-in for a short period. During the shut-in period, gas continues to flow into the wellbore, and the reservoir pressure around the well can build up to a point at which when the well is re-opened it can unload itself. Then, the well can produce briefly but quickly load up and dies again.
- After re-opening the well (kick-off operation) towards torch, there are signs of producer water in the quagmire (onset of liquid slugs at the surface). This producer

water is the result of water loaded in the production column which caused the production decline.

1.3.4. The Candidate Wells in Hassi R'mel Gas Field for the Liquid Loading Study

Based on the previous points which explain the indicators of liquid loading from the well's historical data in gas condensate wells of the Hassi R'mel field, we selected two wells for this study; they are HR055 and HRD023. And based on the internal information from the production and reservoir engineers in the Hassi R'mel field, these two wells considered as the first wells that recently indicate the presence of liquid loading. The two wells represent a typical example of liquid loading warning signs in Hassi R'mel's gas wells. Also, and due to available data, we selected two other wells named HR104 and HR101 to understand and predict the liquid loading problem.

1.3.5. The Production History of Candidate Wells

- **The well HR055**

The well HR055 was drilled in 1973 in the central zone to an ending depth of 2222 m. In doing so the gas-bearing formation of the Triassic (levels A, B, and C) was encountered. It was linked to the MPP1. The well was put on production in 1978; it had an initial gas rate of approximately 2100 (e3sm^3/d). The production history of the well is given in **figure (1.8)**.

As the completion is equipped with a 7" tubing and a 7" liner, and as the produced rates are low, it is impossible to discharge liquids through such a big borehole completion. This condition certainly leads to an increase in the bottom level with liquids. The accumulation of the liquid on the bottom of the well involved liquid loading problem decreases the production performances of the well. To avoid a complete breakdown of the well, it was shut-in several times for building-up a pressure. In **figure (1.6)** the production history of the well HR055 from July 2019 to December 2019 is given to indicate the impact of the accumulation of liquids in the production column; it shows the allocated gas flow-rate and the wellhead pressure versus time.

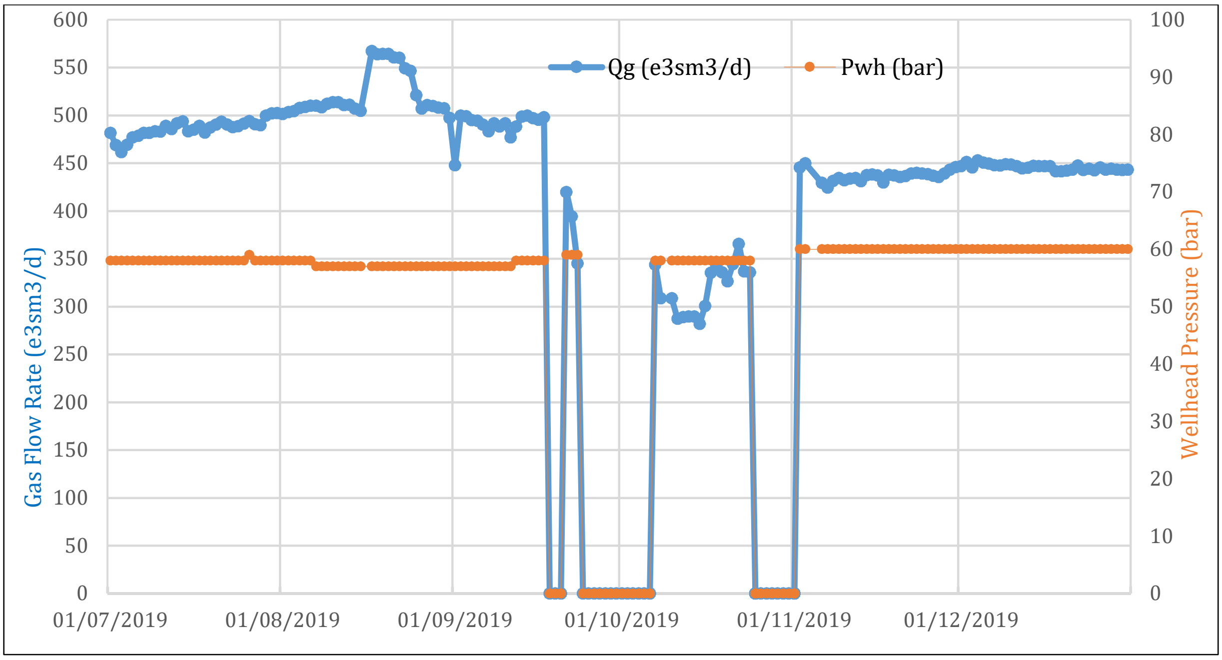

Figure (1.6): Production History of the Well HR055 from July to December 2019 [9]

From the figure above, we notice that the well HR055 was producing with a stable production decline which is about 500 (e3sm^3/d). In this period, the flowing tubing head pressure remains fairly constant at about 58 bars. Then, the gas rate goes out of trend and the liquid loading rate is reached. The liquid continues to accumulate on the bottom of the well till the formation of the water column. To eliminate this water column, the well was switched to the cyclic shut-in production control. So, the well was shut-in for a short period (three days). During the shut-in period, gas continues to flow into the wellbore and near well region, with some pressure increase. When the well was re-opened (kick-off operation), it unloaded itself and produced with meta-stable flow-rate but it quickly loaded up and dies again. Then it was shut-in for a long period (13 days). After that, the well was kicked off but it still produced with meta-stable flow-rate.

To minimize the water influx, an operation of RPM was realized in 10/08/2019 to determine the GWC; the GWC was estimated at the absolute depth of -1445 m. Consequently, a plug was put at the depth of -1433.85 m to isolate the flooded reservoir. Then, the well was re-opened with a stable gas flow-rate of about 450 (e3sm^3/d).

The pose of bridge plug is the most used solution to plug the flooded reservoir to eliminate the water loading at the bottom of the well. To guarantee the production of the well in the future a velocity string is decided to be installed in the well, but this is describing in much more detail in chapter four.

- **The Well HRD023**

The well HRD023 was drilled in 2007 in the south zone to its end depth of 2250 m. The perforated level of this well is the level C. The well was put on production some months later; it had an initial gas rate of approximately 1200 (e3sm^3/d). It was linked to the MPP2. The production history of this well is given in **figure (1.8)**.

Due to the low production gas rate and the completion installation (7" tubing and 7" liner), the discharge condition for the liquid is too low so that the liquid loading is occurring. As we explain in well HR055 before, to avoid the charging of liquids at the bottom of the well, the well HRD023 was shut-in several times for building-up a pressure. In **figure (1.7)** the production history of the well HRD023 from January 2019 to December 2019 is given to indicate the impact of the accumulation of liquid in the production column. The allocated gas flow-rate and the wellhead pressure are plotted as a function of time.

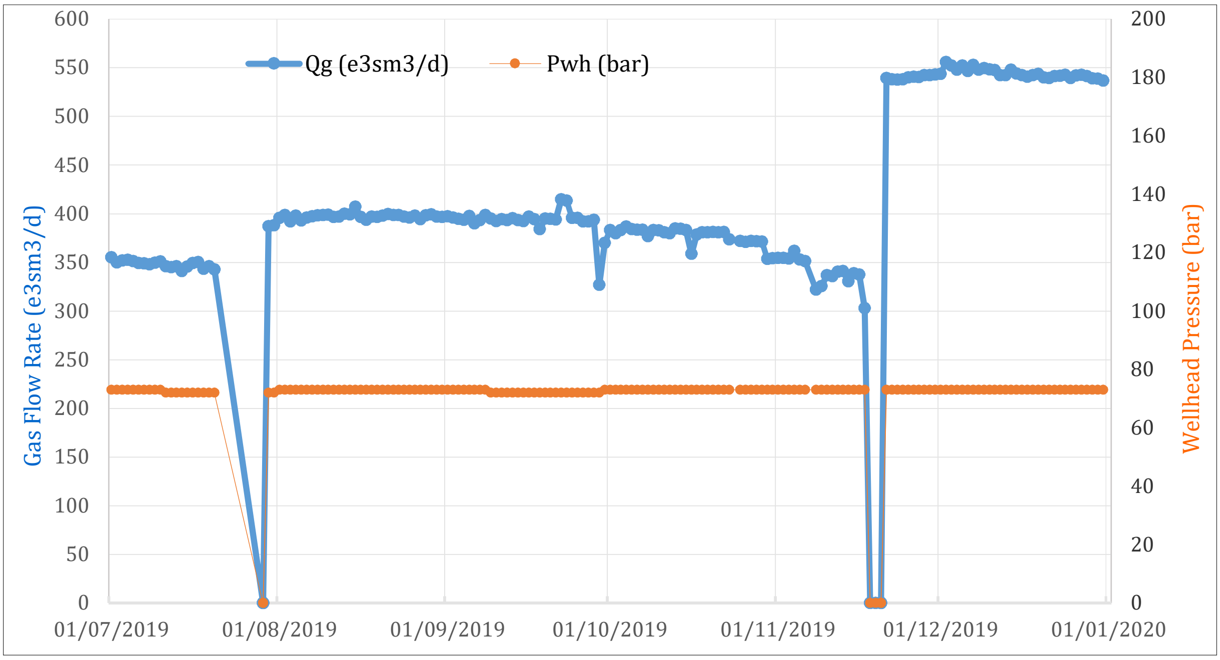

Figure (1.7): Production History of the Well HRD023 from January to December 2019 [9]

Based on the figure above, we notice that the well HRD023 was producing with a stable production decline which is about 350 (e3sm^3/d). In this period, the flowing tubing head pressure remains fairly constant at about 73 bars. Then, the well was shut-in for a short period (two days). After re-opening the well, it was producing with a stable gas rate of about 400 (e3sm^3/d). After a few days later, the gas rate goes out of trend (meta-stable flow-rate) and the liquid loading rate is reached. The liquid continues to accumulate on the bottom of the well till the formation of the water column and the well died. During the shut-in period, gas continues to flow into the wellbore and the pressure increases. When the well was re-opened (kick-off operation), it produced with stable flow-rate of about 540 (e3sm^3/d) and with a wellhead pressure of about 73 bar.

- **The Well HR104**

The well HR104 was drilled in 1977 in the north zone to its end depth of 2254 m. The perforated level of this well is the level C. The well was put on production in 1980; it had an initial gas rate of approximately 1300 (e3sm^3/d). It was linked to the MPP3. The actual average gas rate is about 650 (e3sm^3/d). The production history of this well is represented in **figure (1.8)**.

- **The Well HR101**

The well HR101was drilled in 1977 in the north zone to its end depth of 2300 m. The perforated level of this well is the level A. The well was put on production in 1980; it had an initial gas rate of approximately 1900 (e3sm^3/d). It was linked to the MPP3. The actual average gas rate is about 950 (e3sm^3/d). The production history of this well is represented in **figure (1.8)**.

The **figure (1.8)** below shows the annual gas production for the previous wells:

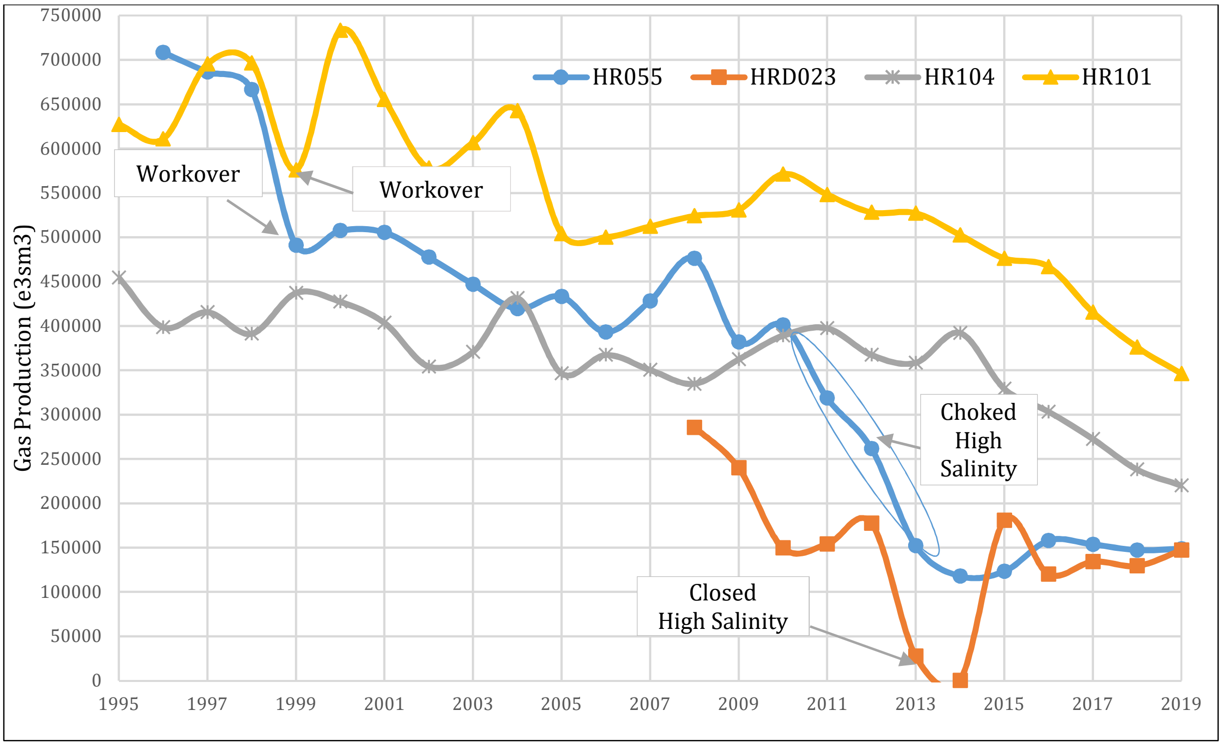

Figure (1.8): The Annual Gas Production History of the Selected Wells [9]

The **figure (1.9)** shows the decline of average reservoir pressure of the well HR104 and HR101:

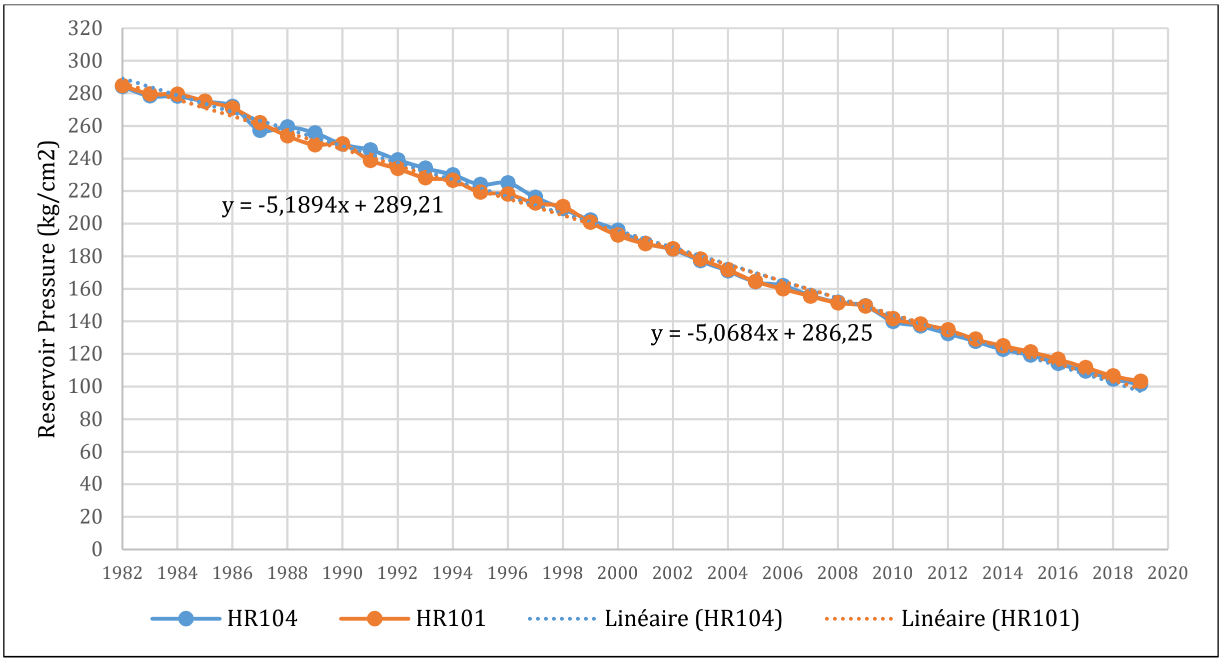

Figure (1.9): The Reservoir Pressure of the Wells HR104 and HR101 [9]

These curves show that the reservoir pressure decline is linear with a slope of 5 kg/cm^2 per year.

Conclusion

The bottom line from this chapter is that every gas well will, at some point in its life, reach a condition where the gas rate is insufficient to carry the co-produced liquids to the surface. After this condition is reached, some fraction of the produced liquids will flow counter-current to the gas and accumulate at the bottom of the well, this results in a sharp reduction in the gas production rate, and in the worst case the well might die completely. A more common result of liquid loading is that the well stabilizes at a lower production rate (meta-stable rate). In this case, some of the water can be entrained by gas to the surface.

Chapter 2

Gas Wells Performance Modeling in Hassi R'mel Field

1. System Nodal Analysis
2. Overview of the Software Pipesim
3. Candidate Wells Modeling

Preface

The objective of this chapter is the modeling of the actual status and well performance for the candidate wells, using available data of well, to define the well model and adjust the actual production data with simulated well behavior, the system Nodal Analysis has been implemented by the software Pipesim.

2.1. System Nodal Analysis

The system Nodal Analysis has been applied for many years to analyze the performance of systems composed of interacting components. The procedure of Nodal Analysis consists of dividing the system into two subsystems at a certain location called nodal point (node). [7] The nodal point can be located anywhere in the system. However, practically, locating a nodal point at the bottom hole (at the mid-perforation depth) is very common. [14] In this case, the first subsystem takes into account inflow from the reservoir to the nodal point (IPR), while the other subsystem considers outflow from the nodal point to the surface (TPR or VLP). The curves formed by this relation on the pressure-rate graph are called the inflow curve and the outflow curve, respectively. The point where these two curves intersect denotes the optimum operating point, as shown in **figure (2.1)**, where the following requirements are satisfied: [23] [16]

- Flow into the node equals flow out of the node
- Only one pressure can exist at a node

At a particular time in the life of the well, there are always two pressures that remain fixed and are not functions of flow rate. One of these pressures is the average reservoir pressure P_r, and the other is the system outlet pressure. The outlet pressure is usually the separator pressure P_{sep}, but if the well is controlled by a surface choke the fixed outlet pressure may be the wellhead pressure P_{wh}. [7]

Once the node is selected, the node pressure is calculated from both directions starting at the fixed pressure:

- Inflow to the node: $P_{node} = P_r - \Delta P$ (upstream components)
- Outflow from the node: $P_{node} = P_{sep} + \Delta P$ (downstream components)

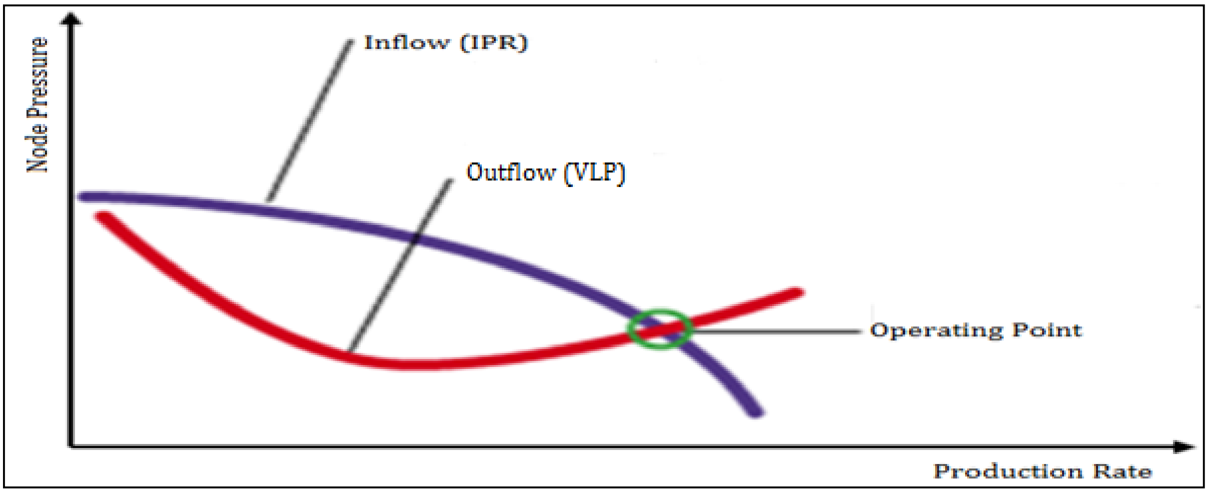

Figure (2.1): The Operating Point [7]

2.2. Overview of the Software Pipesim

Pipesim software is a Steady State multiphase flow simulator for modeling wells and networks, developed by Schlumberger. It is used for the design and diagnostic analysis of oil and gas production systems. Pipesim software tools model multiphase flow from the reservoir to the wellhead. It also analyzes flow-line and surface facility performance to generate comprehensive production system analysis. [15]

With advanced Pipesim modules including well modeling, nodal analysis, PVT analysis, system analysis, artificial lift, and network simulation, Pipesim software helps to optimize and predict production and injection operations. The essential topics are:

- Analyze well performance;
- Model pipeline and facilities;
- Perform nodal analysis;
- Artificial lift design;
- Develop black oil and compositional fluid models;
- Select multiphase flow correlations;
- Model surface networks using GIS map.

2.3. Candidate Wells Modeling

Using Pipesim software, we will model the previously chosen wells (HR055, HRD023, HR104, and HR101) for the study of liquid loading. Building a well model includes several aspects:

1. Well's completion;
2. PVT data;
3. Reservoir's model (IPR);
4. Choice of the vertical flow correlation (VLP);
5. Plot the inflow (IPR) and outflow (VLP) curves.

2.3.1. Well's Completion

The well model to be designed with Pipesim includes a part representing the physical model of the well. The **table (2.1)** summarizes the completion data necessary to create our wells' model.

Table (2.1): Wells' completion [9]

Well	Equipment	Depth (m)		Outside Diameter (in)	Inside Diameter (in)
		From	To		
HR055	Casing 9"5/8	0	2096	9.625	8.681
	Liner 7"	2050	2206	7	6.184
	Tubing 7"	0	2042	7	6.184
	SSSV	2041.5		-	1.97
HRD023	Casing 9"5/8	0	2190	9.625	8.681
	Liner 7"	2082	2223	7	6.184
	Tubing 7"	0	2019	7	6.184
	SSSV	2014.5		-	2.24
HR104	Casing 9"5/8	0	2146	9.625	8.681
	Liner 7"	2102	2254	7	6.276
	Tubing 7"	0	2081	7	6.184
	SSSV	2080.5		-	1.97
HR101	Casing 9"5/8	0	2165	9.625	8.681
	Liner 7"	2135	2241	7	6.184
	Tubing 7"	0	2124	7	6.184
	SSSV	2102.5		-	2.24

2.3.2. PVT Data

To have a reliable model representing the maximum accuracy of flow in our wells, we must integrate the PVT data of the effluents of these wells. The model to be used is the compositional fluid model.

The compositional fluid modeling involves defining mole fractions for each molecular component of the petroleum fraction. The **table (2.2)** shows the data necessary to create this model.

Table (2.2): The components of Hassi R'mel's raw gas [4]

Components	Molar percentage (%)
Water (H_2O)	0.338
Helium (H_2)	0.169
Nitrogen (N_2)	5.307
Carbon Dioxide (CO_2)	0.16
Methane (C_1)	80.326
Ethane (C_2)	7.358
Propane (C_3)	2.872
Isobutane (IC_4)	0.601
Butane (C_4)	1.077
Isopentane (IC_5)	0.36
Pentane (C_5)	0.484
Hexane (C_6)	0.593
Heptane plus (C_{7+})	0.355

Other production data are necessary to create the compositional model; they are represented in the **table (2.3)**.

Table (2.3): Production Data of the Candidate Wells [9]

	HR055	HRD023	HR104	HR101
GOR (sm^3/sm^3)	54825	47530.84	60324.58	128388.30
LGR ($sm^3/MMsm^3$)	24.90	23.49	18.06	9.21
Wcut (%)	26.75	10.45	8.23	15.47
WGR ($sm^3/MMsm^3$)	6.66	2.46	1.49	1.42
Salinity (g/l)	40	25	0	0

2.3.3. Reservoir's Model (IPR)

Using Pipesim, the vertical completion models simulate flow between the reservoir and bottom-hole using Inflow Performance Relationships (IPR). The IPR has been developed to model the flow of fluids from the reservoir, through the formation, and into the well. They are expressed in terms of the well static (or reservoir) pressure P_r, the well flowing (or bottom-hole) pressure P_{wf} and flow rate Q. Typically, for gas IPR the stock tank flow rates are roughly proportional to the square pressure drawdown: [15]

$$Q_g \propto (P_r^2 - P_{wf}^2) \qquad (1)$$

Pipesim offers a comprehensive list of IPR options, for gas condensate reservoir, as follows: Backpressure Equation, Jones, Pseudo Steady State Equation (Darcy), Transient, and Well IP (Productivity Index). [15]

Based on the data available in the Hassi R'mel field, we used the Pseudo Steady State equation (Darcy) to specify the IPR for our wells. The PSS equation is derived from the equation for the single-phase flow of Darcy into a well, it is written in terms of the stock tank flow rates. [19] For gas flow, the formation volume factor can be expressed in terms of pressure and temperature.

$$B_g = \frac{V}{V_s} = \frac{ZRT}{P}\frac{P_s}{Z_s R T_s} \qquad (2)$$

The reservoir pressure is taken to be the average pressure in the reservoir.

$$P = \frac{P_r + P_{wf}}{2} \qquad (3)$$

This gives a stock tank flow rate.

$$Q_g = \frac{Q_r}{B_g} \qquad (4)$$

$$Q_g = \frac{Kh(P_r^2 - P_{wf}^2)}{1422\mu_g TZ[\ln\left(\frac{r_e}{r_w}\right) - 0.75 + S} \qquad (5)$$

The **table (2.4)** gives the data necessary to model the IPR of wells in this study.

Table (2.4): The Reservoir Data of Candidate Wells [9]

Wells	Perforated Levels (m)	h (m)	K (md)	Pr (bar)	Tr (C°)	rw (in)	re (m)	S
HR055	A: 2111÷2123.8	10.8	207	89	89	4.25	650	0
	B: 2138÷2144	5	50					
	C: 2160.4÷2180	13.6	340					
HRD023	C: 2199.5÷2214	14.5	506	98	89	4.25	800	1
HR104	C: 2230÷2244	13.5	182	99	89	4.25	600	4
HR101	A: 2196.7÷2220	13.2	216	103	89	4.25	900	2

2.3.4. Choice of the Vertical Flow Correlation (VLP)

The fluid that is produced at the bottom of the well has to flow to the surface overcoming the sum of the tubing head pressure plus the hydrostatic pressure due to the flowing fluid plus the friction forces due to flow in the tubing and any other energy losses. The flow from the bottom hole of the well to the wellhead is described by the Vertical Lift Performance Relationship (VLP). The VLP depends on many factors including fluid PVT properties, well depth, tubing size, surface pressure, water cut, and GOR.

To build a reliable well model, we need to choose an adequate vertical flow correlation. This correlation should be the one that gives the smallest error compared to the measured data. Pipesim offers multitude correlations to model the VLP, [15] among which we cite:

- The correlation of Beggs and Brill Original (BBO);
- The correlation of Beggs and Brill Revised (BBR);
- The correlation of Duns and Ros (DR);
- The correlation of Hagedorn and Brown (HB);
- The correlation of Mukherjee and Brill (MB);
- The correlation of Orkiszewski (Ork).

Given the lack of data, especially the well-flowing pressure P_{wf}, we will take advantage of the availability of data of the wellhead pressure P_{wh}, and we will proceed as follow to determine the suitable vertical correlation:

1. Enter the previous well data by placing the node at the bottom of the well.
2. Enter the stock tank gas flow rate.

3. Choose the outlet pressure (wellhead pressure) as a variable to calculate.
4. Select the above correlations as vertical flow correlations.
5. From the generated curves, we will have a wellhead pressure for each correlation.
6. The most adequate correlation is that which gives a wellhead pressure close to that measured.

The **table (2.5)** gives the results of different correlations cited above.

Table (2.5): The Relative Errors of Wellhead Pressure of the Vertical Flow Correlations

		BBO	BBR	DR	HB	MB	Ork
HR055	P_{wh} measured (bar)	59	59	59	59	59	59
	P_{wh} calculated (bar)	57.93	58.58	44.51	65.61	69.43	26.59
	E_r (%)	1.82	0.72	24.56	11.20	17.68	54.93
HRD023	P_{wh} measured (bar)	73	73	73	73	73	73
	P_{wh} calculated (bar)	65.71	66.19	52.05	72.49	76.75	31.09
	E_r (%)	9.99	9.33	28.69	0.69	5.13	57.41
HR104	P_{wh} measured (bar)	65	65	65	65	65	65
	P_{wh} calculated (bar)	57.64	57.71	47.75	63.22	67.84	34.46
	E_r (%)	11.32	11.22	26.53	2.74	4.37	46.98
HR101	P_{wh} measured (bar)	65	65	65	65	65	65
	P_{wh} calculated (bar)	67.82	66.22	52.91	65.96	70.88	47.29
	E_r (%)	4.34	1.88	18.60	1.47	9.04	27.24

From the table above, we find that the correlation of **Hagedorn and Brown** gives the closest wellhead pressure to the measured values for the wells HRD023, HR104, and HR101. Therefore, this correlation will be used for the calculation of the tubing pressure losses of these three wells. In the same context, the correlation of **Beggs and Brill Revised** will be used for the well HR055.

2.3.5. Plot the Inflow (IPR) and Outflow (VLP) Curves

Using the Nodal Analysis, we will study the current performance of our wells and this to determine the operating point (Q_g, P_{wf}) of each well. For this, we will plot the inflow (IPR) and outflow (VLP) curves for each well.

Both IPR and VLP relate the wellbore flowing pressure to the surface production rate. While the IPR represents what the reservoir can deliver to the bottom-hole, the VLP represents what the well can deliver to the surface. The intersection between the two curves gives the operating point.

We fix the outlet pressure as the wellhead pressure P_{wh}. The figures in **Appendix 1** illustrate the curves inflow and outflow for the wells HR055, HRD023, HR104, and HR101. From these curves, we determine the flowing bottom-hole pressure P_{wf} and the gas flow-rate Q_g corresponding to the operating point as shown in **table (2.6)**.

Table (2.6): The Operating Points of Studied Wells

	Q_g at NA point (e3sm^3/d)	P at NA point (bar)
HR055	446.80	86.88
HRD023	543.49	95.76
HR104	628.11	88.30
HR101	965.07	90.99

Given the lack of data of bottom-hole pressure and comparing between the current reel gas production rate: (448 (e3sm^3/d) for HR055, 544 (e3sm^3/d) for HRD023, 626 (e3sm^3/d) for HR104, and 962 (e3sm^3/d) for HR101) and that obtained by Pipesim (447 (e3sm^3/d) for HR055, 543 (e3sm^3/d) for HRD023, 628 (e3sm^3/d) for HR104, and 965 (e3sm^3/d) for HR101); which are very close, we ensure that the models constructed represent the wells with sufficient precision. **Table (2.7)** shows the main results of wells modeling.

Table (2.7): The Mainly Results of Wells Modeling

	Q_g (e3sm^3/d)	P_r (bar)	P_{wf} (bar)	P_{wh} (bar)
HR055	447	89	87	59
HRD023	543	98	96	73
HR104	628	99	88	65
HR101	965	103	91	65

Conclusion

The Nodal Analysis system has used to define the well model and adjust the actual production data with simulated well behavior. Once the model has been created and verified to reproduce the current behavior, a sensitivity analysis will be performed to identify, predict, and solve the liquid loading problem and to evaluate the future wells' behavior.

Chapter 3

Identification and Prediction of Liquid Loading in Hassi R'mel Gas Wells

1. Liquid Loading Onset Prediction Methods
2. Liquid Loading Onset using Pipesim Software
3. Identification of Liquid Loading in Candidate wells using Pipesim
4. Prediction of Liquid Loading in Candidate wells using Pipesim

Preface

Based on the wells models created in the previous chapter, this chapter can discriminate, if there is accumulated liquid in the bottom-hole by comparing the intersection production of the inflow and the outflow curves with the critical rate production of gas wells. The critical rate is the basis to identify and to predict the onset of liquid loading in the bottom-hole. If the critical gas rate is higher than the intersection one, the liquids will load in the wellbore.

3.1. Liquid Loading Onset Prediction Methods

To prevent liquid loading in gas wells, it is important to predict the onset of liquid loading. Since 1969, many authors have suggested several methods to determine if the flow rate of a well is sufficient to remove the liquids. [12] Discussed below are the basics of Turner et al. model (1969) which have been applied in this study.

Turner et al. was the first correlation proposed to identify and predict liquid loading. Turner discovered that liquid loading could best be predicted by a droplet model that showed when droplets move up (gas flow above critical velocity) or down (gas flow below critical velocity). [10]

By analyzing a large database of producing gas wells, Turner et al. developed a simple correlation to predict the so-called critical velocity in near-vertical gas wells assuming the droplet model. In this model, the droplet weight acts downward (gravitational forces) and the drag force from the gas acts upward, as shown in **figure (3.1)**. When the drag is equal to the weight, the gas velocity is at "critical". Theoretically, at the critical velocity the droplet would be suspended in the gas stream, moving neither upward nor downward. If the gas velocity is above a critical velocity, the drag force lifts the droplet, otherwise, below the critical velocity, the droplet falls and liquids accumulate in the wellbore (liquid loading). [21]

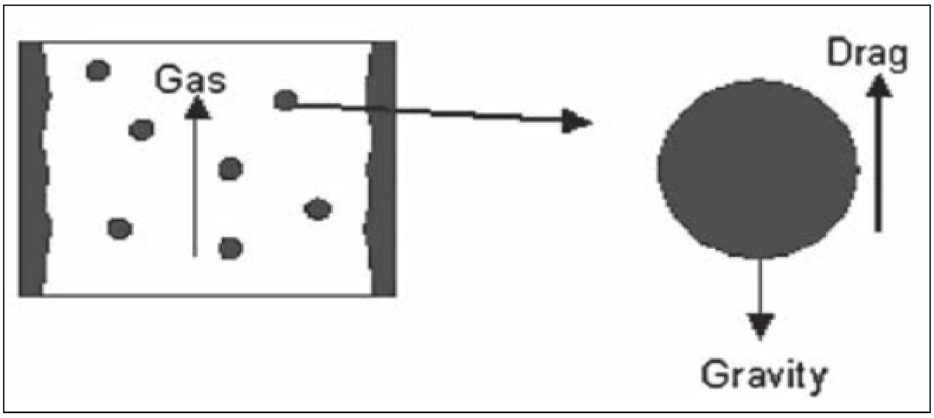

Figure (3.1): Liquid Droplets Transport in Vertical Gas Stream [21]

The industry has gained considerable experience in applying the Turner equation in different scenarios and how to modify it to match field observation. As presented in **table (3.1)**, several investigations have suggested different modified expressions derived from the Turner model.

Table (3.1): Review of Turner Equation [21]

Authors	Modifications of Turner Correlation
Turner et al., 1969	Created the widely accepted Turner equation
Coleman et al., 1991	Suggested not to use the 20% correction factor for low-pressure gas wells
Nosseir et al., 2000	Considered influences from different flow regimes
Li et al., 2002	Involved the droplet's shape
Veeken et al., 2003	Defined the concept of Turner ratio
Guo et al., 2006	Took the minimum required kinetic energy of gas flow into account
Befroid et al., 2008	Concerned with the effects due to wellbore inclination
Sutton et al., 2010	Used more realistic PVT properties
Zhou and Yuan, 2010	Included the liquid droplet concentration in gas wells
Veeken et al., 2010	Designed a specific expression for offshore gas wells
Luan and He, 2012	Comprised droplets rollover in the gas rising process

The likely reason that Turner's method is so popular is that all the parameters needed in the predictive equation can be readily obtained at the wellhead, which is a great convenience for field operators.

3.1.1. The Critical Velocity

In practice, the critical velocity is generally defined as the minimum gas velocity in the production tubing required moving liquid droplets upward.

Turner's model developed two variations of correlations, one for the transport of water and the other for condensate. The fundamental equations derived by Turner were found to underpredict the critical velocity from the database of well data. To better match the collection of measured field data, Turner adjusted the theoretical equations for the required velocity upward by 20%. After the 20 percent empirical adjustment, the critical velocity for condensate and water were presented as follows: [10]

$$V_{c.condensate} = \frac{4.02(45-0.0031P)^{\frac{1}{4}}}{(0.0031P)^{\frac{1}{2}}} \dots\dots (6)$$

$$V_{c.water} = \frac{5.62(67-0.0031P)^{\frac{1}{4}}}{(0.0031P)^{\frac{1}{2}}} \dots\dots (7)$$

P: pressure (psi)

$V_{c.condensate}$, $V_{c.water}$: the critical velocity for condensate and water (ft/sec)

The theoretical equation for critical/terminal velocity V_t to lift a liquid drop is given by:

$$V_t = \frac{1.593\sigma^{\frac{1}{4}}(\rho_l-\rho_g)^{1/4}}{\rho_g^{1/2}} \dots\dots (8)$$

V_t: Terminal velocity of the liquid droplet (ft/s)

σ: Interfacial tension is taken as 60 (dynes/cm)

ρ_l: Liquid-phase density (lbm/ft^3)

ρ_g: Gas-phase density (lbm/ft^3)

This equation predicts the minimum critical velocity required to transport liquids in a vertical wellbore. They are used most frequently at the wellhead with P being the flowing wellhead pressure. When both water and condensate ere produced by the well, Turner recommends using the correlation developed for water because water is heavier and requires a higher critical velocity.

Note that the actual volume of liquids produced does not appear in this correlation and the predicted terminal velocity is not a function of the rate of liquid production.

3.1.2. The Critical Rate

Although critical velocity is the controlling factor, one usually thinks of gas wells in terms of production rate rather than the velocity in the wellbore. These equations are easily converted into a more useful form by computing a critical well flow rate. From the critical velocity V_c, the critical gas flow rate Q_{cg} may be computed from:

$$Q_{cg} = \frac{V_c A}{B_g} \qquad (9)$$

Where B_g is the gas formation volume factor defined as follows:

$$B_g = \frac{Z\ T\ P_{sc}}{P\ T_{sc}} \qquad (10)$$

Substituting for standard conditions, Pressure P_{sc} = 14.65 psi and Temperature T_{sc} = 520°R, the critical gas flow rate can be written as:

$$Q_{cg} = \frac{3.06\ P\ V_c\ A}{(T+460)Z} \qquad (11)$$

$$A = \frac{\pi\ d_t^2}{4*12^2} \qquad (12)$$

Q_{cg}: Critical gas flow rate (MMscf/d)   A: Tubing cross-sectional area (ft^2)

T: Surface temperature (°F)   P: Surface pressure (psi) d_t: tubing inside diameter (in)

3.2. Liquid Loading Onset using Pipesim Software

Using Pipesim, liquid loading calculations are performed in every task and are available for review in plots and reports. Based on the Turner equation for calculating critical velocity, Pipesim calculates a liquid loading velocity ratio (LLVR), which is the minimum lift velocity (terminal/critical velocity), divided by the fluid velocity. An LLVR > 1 indicates a liquid loading risk because the fluid is flowing at a velocity lower than the minimum velocity required to lift the liquids and prevent loading.

Pipesim uses the Nodal Analysis to determine the three main parameters of liquid loading along the well's profile; these parameters are the liquid loading gas rate (the critical gas rate), the liquid loading velocity (the critical velocity) and the liquid loading velocity ratio.

3.3. Identification of Liquid Loading in Candidate wells using Pipesim

As mentioned earlier, using the nodal analysis system, the selected vertical correlations were used to calculate the pressure, gas flow rate, and gas and liquid velocities at incremental depths from the surface to the bottom of the well. The critical gas velocity and the critical rate profiles were then calculated using Turner's equation. The **table (3.2)** shows the results of the operating gas flow rate, the maximum critical rate, and the maximum liquid loading velocity ratio over the entire depth for each candidate well.

The loading condition of the gas well is obtained by comparing the critical rate with the operating gas rate. If the operating rate is greater than the critical rate, it means the well is unloaded otherwise it is loaded up.

Table (3.2): The Liquid Loading Parameters

	Q_g (e3sm^3/d)	Q_{cg} (e3sm^3/d)	LLVRm
HR055	447	559	1.25
HRD023	543	585	1.08
HR104	628	569	0.9
HR101	965	583	0.6

From this table and by comparing the operating gas flow rate with the critical gas rate, it can be seen that the operating flow rate is below the critical gas rate to avoid liquid loading for the wells HR055 and HRD023. Also, the liquid loading velocity ratio is upper than 1 which means that the actual gas velocity is lower than the liquid loading critical velocity. Therefore, the wells are loading up.

In the same context, it can be observed from this table that the operating flow rate is above the critical gas rate to avoid liquid loading for the wells HR104 and HR101. Also, the liquid loading velocity ration is lower than 1. So, there is no onset of liquid loading risk at these conditions.

To determine where the liquid loading will be occurring in the well's profile, we plot the liquid loading velocity ratio profile as a function of depth as shown in **figure (3.2)**. These curves are plotted based on the data obtained from Pipesim, these data are detailed in the **table (3.3)** and the **table (3.4)** respectively for the well HR055 and the well HRD02, while the data for the other wells (HR104 and HR101), where there is no initial of liquid loading, they are exhibited in **Appendix 2**.

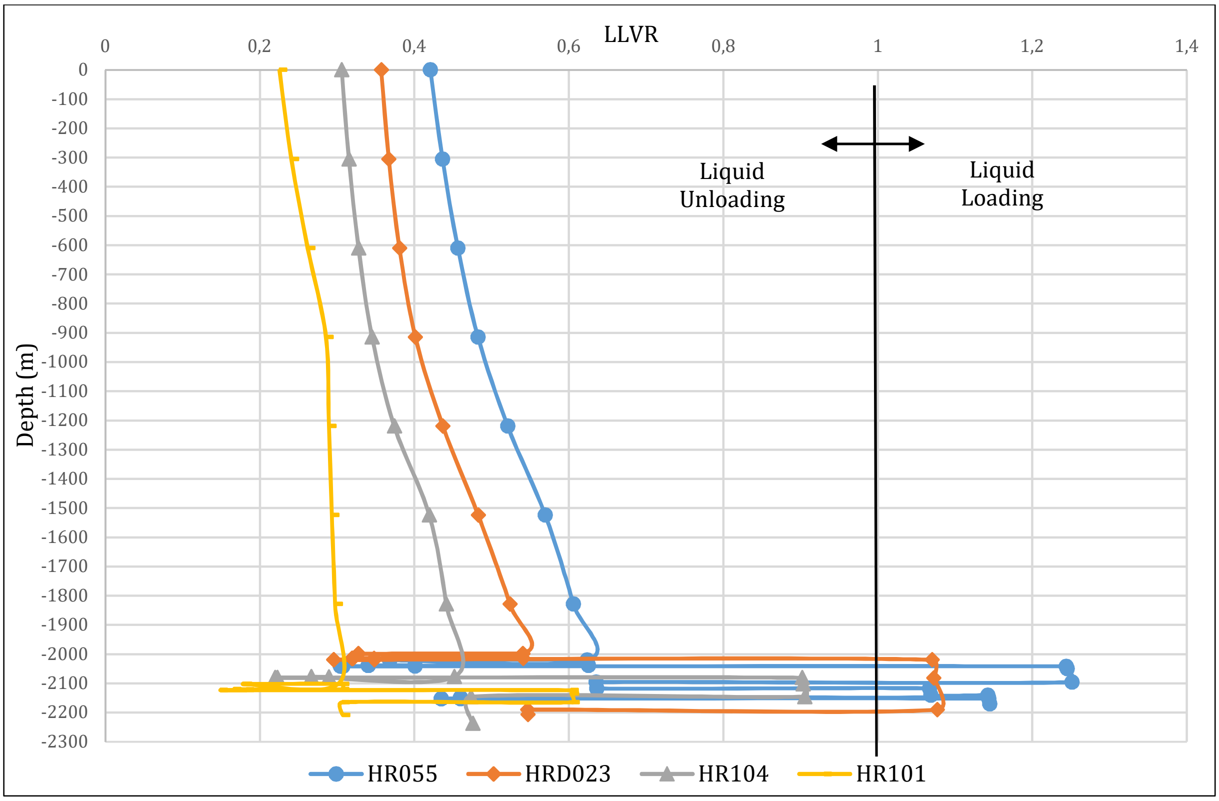

Figure (3.2): The Profile of Liquid Loading Velocity Ratio as a Function of Depth

These curves depict that the LLVR for the wells HR104 and HR101 are lower than 1 over the entire depth, which is explained by no liquid loading. Therefore, these wells will be used to predict the initial of the liquid loading as clarified in the next section.

By looking into these curves and the tables below; it is seen that the critical velocity is higher than the gas velocity (LLVR is higher than 1) at some points in the well string, for the wells HR055 and HRD023; so the liquids accumulate in these depths. This means that the gas velocity changes from point to point in the tubing even though the gas rate is constant.

In these conditions, only a part of a co-produced liquid can be carried out, whereas the other part forms loading liquid at the bottom. The accumulation of liquids in the bottom of the wells appears in the section between end tubing and top liner; where the area is largest and the fluid velocity is lowest. Also for the well HR055, the liquids load in front of the perforations. Hence, we deduce that as the tubing diameter is increased the gas flow rate required to lift liquids will be higher than that required to lift when using a smaller diameter. This because an increase in the diameter will lead to an increased surface area, which inadvertently will require more energy for efficiency.

Table (3.3): The Loading Status and the LLVR Profile for the Well HR055

Equipment	Elevation (m)	FMV (m/s)	LLV (m/s)	LLVR	Liquid Status
Perforation C	-2170.206	1.922076	2.196054	1.14476166	Loaded
	-2152.467	1.92737	2.199443	1.14337355	Loaded
	-2152.223	5.070015	2.199552	0.43467578	Unloaded
	-2148.2	4.799846	2.200282	0.45929443	Unloaded
Perforation B	-2141.007	2.064049	2.201592	1.06854696	Loaded
	-2117.415	2.071556	2.206055	1.06682782	Loaded
Perforation A	-2117.415	3.46895	2.204366	0.63606007	Unloaded
	-2095.988	1.765383	2.207011	1.25134715	Loaded
Top Liner 7"	-2049.993	1.776766	2.209712	1.24485533	Loaded
Tubing end	-2041.733	1.778815	2.210065	1.24362125	Loaded
	-2041.489	7.20719	2.210128	0.30694837	Unloaded
Siege 4"313	-2041.276	5.539446	2.217503	0.40069232	Unloaded
	-2039.082	5.540861	2.217531	0.40059514	Unloaded
Siege 4"56	-2038.594	3.550719	2.217569	0.62513555	Unloaded
	-2020.794	6.032431	2.217736	0.36798647	Unloaded
Siege 4"75	-2020.245	3.559493	2.217752	0.62364757	Unloaded
	-1828.8	3.647606	2.207854	0.60589428	Unloaded
	-1524	3.78727	2.154151	0.56944706	Unloaded
	-1219.2	3.930687	2.043959	0.52078097	Unloaded
	-914.4	4.08211	1.965207	0.48233833	Unloaded
	-304.8	4.41072	1.919861	0.43641701	Unloaded
Tubing head	0	4.593893	1.927016	0.42070506	Unloaded

Table (3.4): The Loading Status and the LLVR Profile for the Well HRD023

Equipment	Elevation (m)	FMV (m/s)	LLV (m/s)	LLVR	Liquid Status
Perforation C	-2206.752	3.830513	2.093456	0.54686571	Unloaded
	-2189.988	1.947089	2.095483	1.07689172	Loaded
Top Liner 7"	-2081.997	1.966866	2.107942	1.07240517	Loaded
Tubing end	-2019.3	1.978009	2.11508	1.06997783	Loaded
Siege 4"56	-2018.69	6.084609	2.115287	0.34786683	Unloaded
	-2014.88	6.610325	2.115763	0.32027317	Unloaded
	-2014.515	6.610513	2.115798	0.32026943	Unloaded
Siege 4"75	-2014.393	3.934718	2.125917	0.54063889	Unloaded
	-1998.756	3.940439	2.127739	0.54031708	Unloaded
Siege 4"813	-1998.269	3.940979	2.127905	0.54028507	Unloaded
	-1828.8	4.001675	2.094352	0.52373072	Unloaded
	-1524	4.106146	1.97969	0.48256092	Unloaded
	-1219.2	4.20422	1.834016	0.43678754	Unloaded
	-914.4	4.29216	1.719261	0.4012721	Unloaded
	-609.6	4.370578	1.660087	0.38069654	Unloaded
	-304.8	4.442525	1.625443	0.36689483	Unloaded
Tubing head	0	4.507925	1.604246	0.35703066	Unloaded

By checking the gas velocity at all depths in the tubing, the casing set near the bottom of the well (above perforations) may allow liquid buildup because of the low gas velocity in the large casing since this would be the most likely location of the initial liquid loading. In practice, it is recommended that liquid loading calculations be performed at all sections of the tubing where diameter changes occur. In general for a constant diameter string, if the critical velocity is acceptable at the bottom of the string, then it will be accepted everywhere in the tubing string. [10]

3.4. Prediction of Liquid Loading in Candidate wells using Pipesim

When an accurate forecast of the production rate is made, then the liquid loading moment can be predicted. In this section, we will proceed to predict the onset of liquid loading (the year when the liquid loading will occur) in the wells HR104 and HR101 (these wells actually do not have the liquid loading problem). We plot the predicted gas flow rates and the critical gas flow rates versus the reservoir pressure for each well as illustrated in **figure (3.3)** and **figure (3.4)**. The critical flow rates are calculated based on the Turner criterion while the predicted gas flow rates are calculated based on the IPR for each predicted reservoir pressure (we assumed that the gradient of the reservoir pressure is 5 kg/cm^2/year). We assume a constant WGR and constant GOR for the forecasting purpose and the wellhead pressure will remain as an unchanged constraint at 65 bars for both wells. When the predicted flow rate falls below the Turner critical rate, the liquid loading alert is triggered.

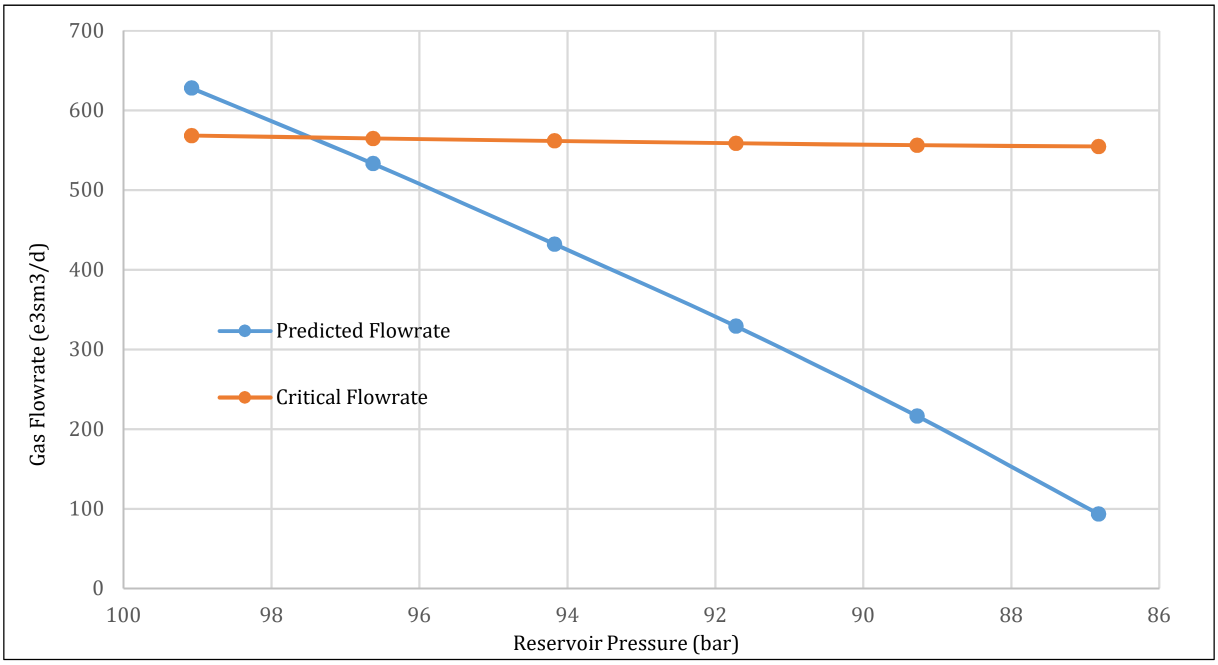

Figure (3.3): Turner Model Prediction Loading for the Well HR104

In accordance with the results obtained for the well HR104, it is observed that the critical gas flow rate will become greater than the predicted gas flow rate from the reservoir pressure of 97.5 bar (corresponding to the year 2021), so the liquid will begin to accumulate in the bottom hole of the well. Over time the gas flow rate decreases until the well will die.

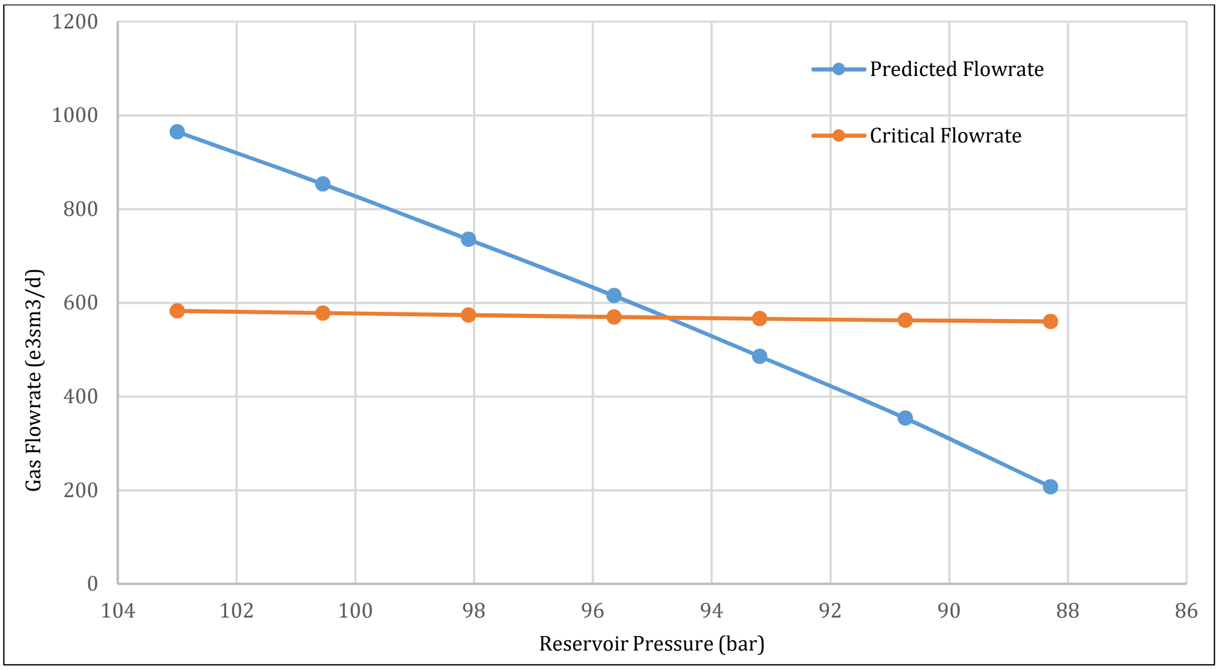

Figure (3.4): Turner Model Prediction Loading for the Well HR101

In accordance with the results obtained for the well HR101, it is seen that the critical gas flow rate will become greater than the predicted gas flow rate from the reservoir pressure of 94.8 bar (corresponding to the year 2022), thus the onset of the liquid loading in the bottom hole of the well. Over time the gas flow rate decreases until the well will die.

Conclusion

We use the Turner model to predict liquid loading by intersecting the Turner curve with IPR and VLP as explained above. Predicting the time and condition where liquid loading starts helps us to take early measures to prevent it leading to proper utilization of resources.

Chapter 4

Solving Liquid Loading Problems in Hassi R'mel Gas Wells

1. Solutions to prevent Liquid Loading Problems
2. Application of Velocity String to solve Liquid Loading Problem in Hassi R'mel's Gas Wells
3. The Impact of Boosting to solve Liquid Loading Problem in Hassi R'mel's Gas Wells

Preface

Once the liquid loading problem is recognized and/or predicted, and in order to reduce the effects of liquid loading on gas production, it is important to design a proper solution to deal with it. Different solutions should be evaluated and compared to find the best course of action when dealing with wells that have liquid loading problems to achieve the highest ultimate gas recovery possible for the well. This chapter depicts the theoretical background of the different methods, curative and preventive, of handling liquid loading in gas wells. Then, we apply some of these methods for the studied wells by changing the working system and then calculate the inflow and outflow curves until the intersection production is bigger than the critical one. Now the working system is the optimum system of removing the accumulated liquids.

4.1. Solutions to prevent Liquid Loading Problems

Many types of techniques of remedial lifting have been developed so far. Most of the techniques focus on increasing gas velocity and artificially water-lifting to postpone and reduce the onset of liquid loading. These deliquification techniques can be subdivided into two categories, namely the methods that use the energy of the well fluids to lift liquids to surface and methods that use an external energy source to lift liquids. These methods may be used singly or in a combination of two or more.

4.1.1. Methods of Sustaining Natural Flow (Well Energy)

The main operations use the own well energy for controlling and handling liquid loading are as follows:

- **Plunger lift:**

Plunger lift is a premier method of operating a gas well with liquids. It uses a free-traveling plunger/piston to assist the gas in carrying liquid upward without an excessive liquid fallback. Periods of flow and no-flow for pressure buildup are required. Plunger lift can operate using the wells' natural energy. The plunger and liquids are lifted by use of gas pressure built up in the tubing and the annulus, if available, while the production valve is closed. [11]

Figure (4.1) illustrates a plunger lift cycle. Pressure builds in the casing with the plunger at the bottom of the well. Next, the well opens and annulus gas expands to lift the plunger and liquid to the surface. Gas flow while the plunger remains at the surface. Liquids accumulate in the well as gas flow decreases. The valve closes and the plunger falls to the bumper spring. Repeating cycles may be adjusted continuously by the use of a plunger lift controller.

The pressure that builds in the annulus during the shut-in portion of the cycle is the major source of energy to bring the plunger and liquid to the surface along with some well inflow. Installations operate best with no packer in the well. Some plunger wells operate with a packer, but greater well pressure and GLR are needed. [11]

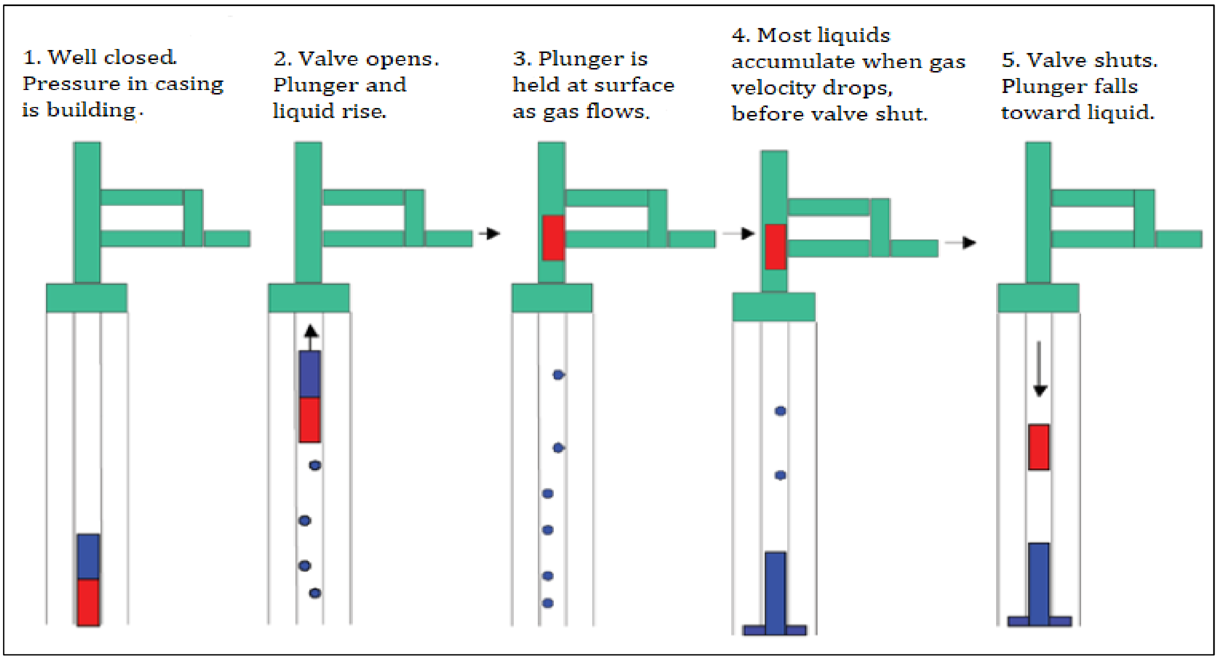

Figure (4.1): Plunger Lift Cycle [8]

- **Velocity String:**

A velocity string is simply "the next size down" for the completion. When a well is new, the production tubing is sized to handle initial gas flow rates and pressures. As wells deplete, pressure and flow rate decline. Therefore, a reasonable solution is to reduce the size of the completion to try to maintain the gas velocities required for liquid transport. Installing a smaller internal diameter tubing string (velocity string) inside the original tubing will create higher gas velocities and may prevent liquid loading. [6] The installation can be up to the surface or just up to any point in the tubing as shown in **figure (4.2)**. Unfortunately, these results in a more restrictive completion, which effectively chokes the well, are reducing the overall flow rate. Besides reduced flow capability, velocity strings are only able to extend the life of a well for a limited period.

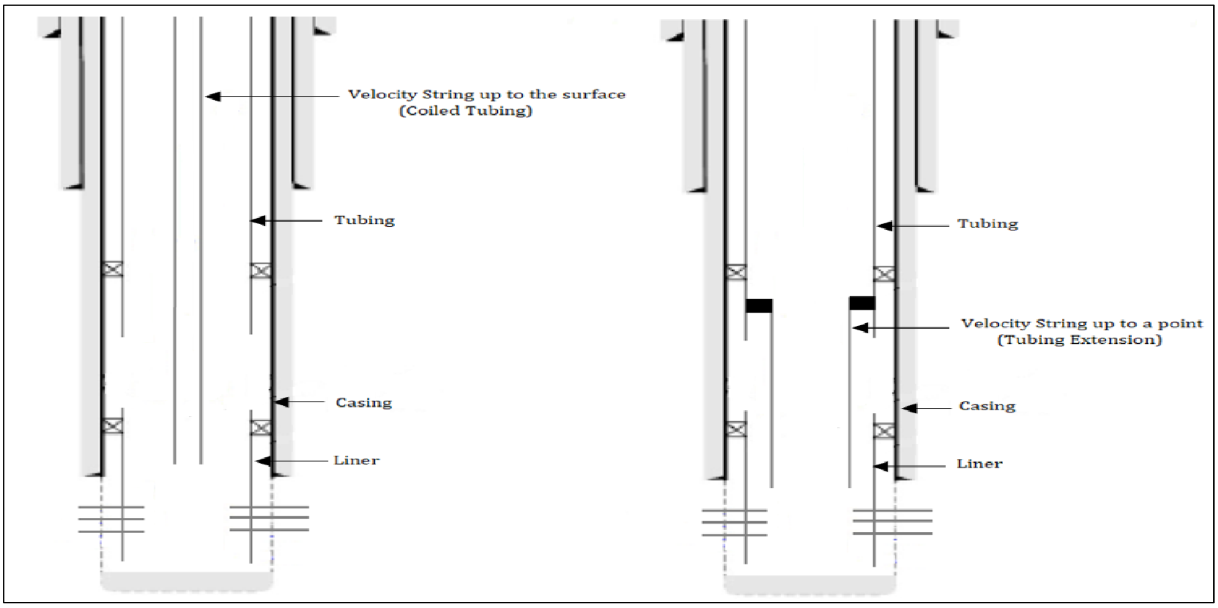

Figure (4.2): The Application of Velocity String for Handling Liquid Loading [6]

- **Cycling (Alternate Flow/Shut-in Periods):**

Cycling a well requires the exact monitoring of well's fundamental data (production rate, wellhead temperature, wellhead pressure). This method involves the shutting in of a gas well that suffers from liquid loading on an appropriate time, to let it build up pressure and then producing the well to a low-pressure system. During the shut-in time the well builds up pressure (gas accumulation) in the near-wellbore region being charged from the reservoir. When opening up the well, this increased pressure might lift some of the liquids that obstruct gas production for a short time and hence gain the well some time until a liquid column of sufficient height has built up again to impact gas production, at which time the well should be shut-in already. [20]

- **Smaller Diameter Production Tubing (Tubing Sizing):**

It is one of the numerous temporary solutions to liquid loading in gas wells. It requires the change of tubing diameter to a smaller tubing to decrease the effective flow area thereby increasing the gas velocity. Tubing performance curves may be used to choose the optimum tubing size. It is ascribed a temporal solution technique because as the reservoir pressure declines it will reach a point where liquids may not be able to be transported up the tubing. The cost of re-completion can be very high to the extent that it is rare among the best options to consider unloading gas wells. [20] Before the installation, the implementation and operating cost must be considered that they are far less compared to the expected revenue using this method.

- **Compression:**

It is a form of maintaining natural flow with lower wellhead pressure. Lowering of the wellhead pressure leads to a lower bottom hole flowing pressure and increased drawdown, which in turn increases the gas flow rate. [18] The use of compressors may not substantially improve the gas rate but will help increase the tubing velocity thus extending the life of the well. [1]

Compression and reduced surface pressure is usually the first tool used in the life of a gas well to keep it deliquified and sometimes the only artificial lift method used, but compression can also be used to increase the effectiveness of other artificial lift deliquification methods including foaming, gas lift, pumping, and velocity string.

4.1.2. Methods of Artificial Lift (External Energy)

Different artificial lift methods have been applied to conquer this challenge. The main operations for controlling and handling liquid loading are as follows:

- **Pumps:**

There are different types of pumps for example ESP (Electrical Submersible Pumps), Rod Pumps, and Hydraulic Pumps. The mechanism is pumping liquid out of the well and through coiled or slim tubing to the surface unit as shown in **figure (4.3)**. The problem of high GOR in cases of pump application and particularly in ESP such as gas locking or fluid pound is usually best addressed by sumping the pump below the perforation or by using a separator. [6]

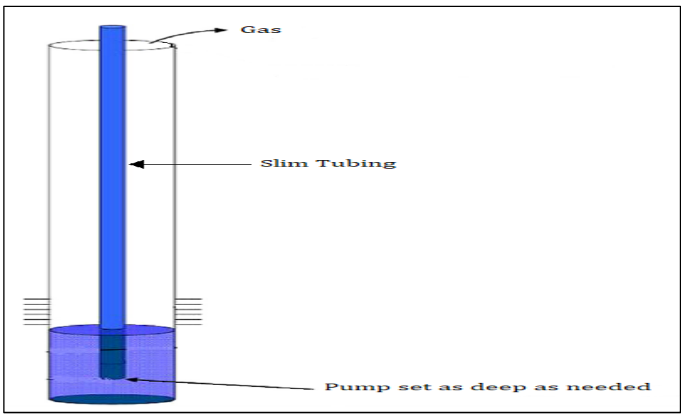

Figure (4.3): The Application of down Hole Pumps for handling liquid loading [6]

- **Gas lift:**

Gas lift is a means of injecting high-pressure external gas into the tubing production as deep as a possible injection point. Typically, in gas wells, the additional gas augments the formation gas to lighten the flowing gradient in the tubing and reduces the flowing bottom hole pressure, thereby increasing the inflow of produced fluids. For dewatering gas wells, the volume of injected gas is designed so that the combined formation and injected gas will be higher than the critical liquid lift rate. [10] Unlike the pumps, the gas lift system does not face any issues with the presence of high GLR production and as has been noted by many it is the closest system to the natural flow. The main challenge in the application of gas lift for gas wells is related to the allocation of gas to groups of wells. [6]

Fundamentally, for lifting accumulated liquids from gas wells, there are two types of gas lift techniques used excessively in the industry which are the continuous gas lift and intermittent gas lift (automated logic system). These applications can be utilized with either conventional tubing with multiple valves mechanism or a coiled tubing application; these completions are shown in **figure (4.4)**.

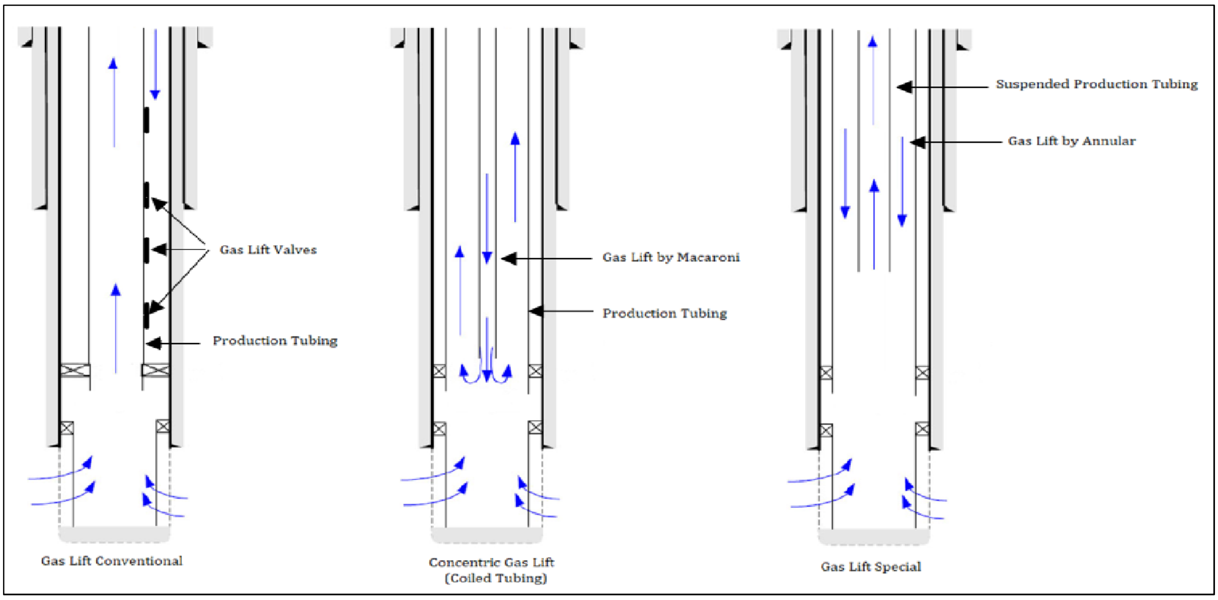

Figure (4.4): The Completion Types of Gas Lift [10] [6]

- **Foam Assisted lift:**

Foaming agents are a very simple and inexpensive means of unloading low productivity gas wells. There are no down hole modifications required and the surface equipment is minimal depending upon the type of treatment and the surfacing foam stability. Foaming agents create a foam which is an emulsion of gas and liquid where the gas bubbles are separated from each other by a liquid film. The objective of using foaming agents is to create a molecular bond between the gas and the liquid phases and to maintain its foam stability for a useful period of time so that the accumulated liquid is transported to the surface in a foamed slurry state. [20]

Foaming agents are more applicable in low rate gas wells producing water. Water molecules are polar and can build relatively high film strengths whereas, light condensate hydrocarbons are non-polar and therefore have less molecular attraction forces between molecules. [20]

4.2. Application of Velocity String to solve Liquid Loading Problem in Hassi R'mel's Gas Wells

In this section, we study the application of the Velocity String as a remedy to solve the liquid loading problem in the gas wells of Hassi R'mel.

4.2.1. The Decision for a Velocity String

The intention behind the installation of a velocity string with a smaller diameter than the production string minimizes the cross-sectional flow area. When the cross-sectional flow area gets smaller, the gas velocity in the tubing will increase. This means; the higher the gas velocity on the bottom of the well, the more energy for transporting the liquid up to the surface is given. Therefore the liquid is not able to accumulate on the bottom of the well anymore. For this reason, recently in the Hassi R'mel field, a velocity string technique has been applied as a remedial technique (curative option) in the well HR055 to reduce the loss of gas production after the liquid loading begins to occur. The application and evaluation of this method in the technical aspect, using Pipesim software, for the well HR055 are gathered in this section. Similarly, this technique will apply to the other studied wells.

4.2.2. Installation of the Velocity String

The installation of the velocity string is from the end of the tubing to the top of perforations (tubing extension) as shown in the **figure (4.5)**. Comparing with a velocity string up to the surface (coiled tubing); the velocity string hanged off into the existing production tubing meets the requirements of future standards. One major criterion was to guarantee the safety of the well by maintaining the functionality of the SSSV.

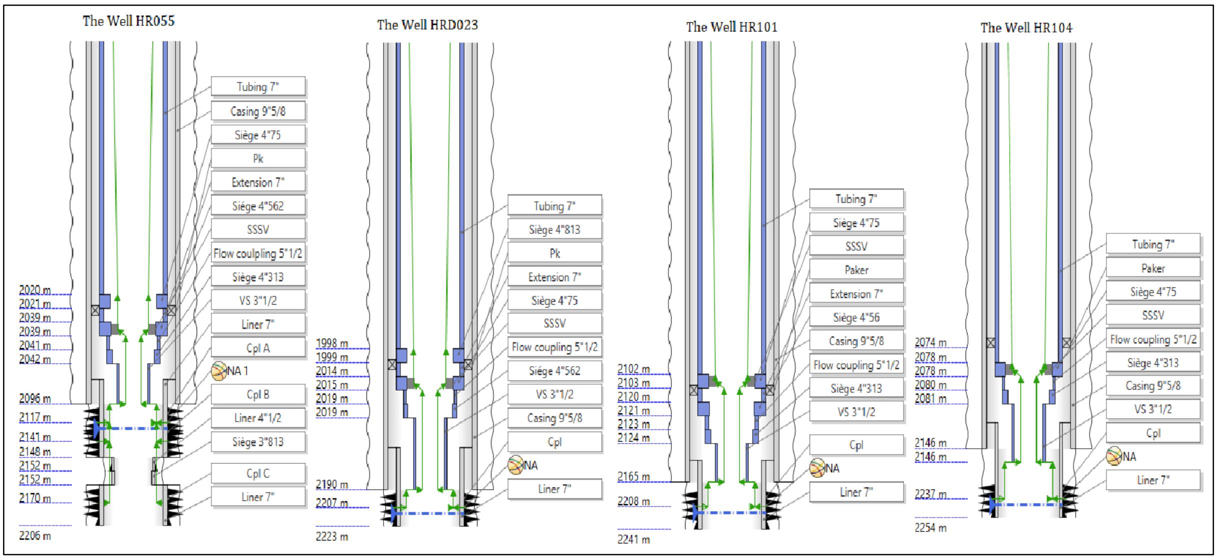

Figure (4.5): The Application of Velocity String using Pipesim Software

4.2.3. Results of Application of the Velocity String

We perform nodal analysis to select an optimum velocity string size that reduces the impact of the liquid loading. The available tubing size has OD of 2”$^{7/8}$ in and 3”$^{1/2}$ in. By applying nodal analysis in these wells, the results obtained are given in the **table (4.1)**.

Table (4.1): The Impact of the Velocity String on the Liquid Loading

	Velocity String 2”$^{7/8}$			**Velocity String 3”$^{1/2}$**		
	Q_g (e3sm^3/d)	Q_{cg} (e3sm^3/d)	LLVRm	Q_g (e3sm^3/d)	Q_{cg} (e3sm^3/d)	LLVRm
HR055	251	285	2.39	362	285	1.48
HRD023	302	299	0.99	400	298	0.74
HR104	527	302	0.57	585	300	0.51
HR101	796	300	0.38	894	298	0.33

As can be seen from the previous table, the velocity string of diameter 3”$^{1/2}$ gives the highest daily gas production. Therefore, this is a very suitable size. This size is also the best option as the wells with this velocity string give the lowest critical rate than without and with the other velocity string size and therefore the wells can produce for a longer period in time.

By comparing the results obtained after installation of velocity string of size 3”$^{1/2}$ with those obtained before installation of velocity string shown in table (3.2) in the previous chapter; the LLVRs for the four wells decreased. Therefore the liquid loading was reduced. For the well HR055, the liquids are still loaded in some depths, but for the well HRD023, the liquids were unloaded over the entire depth; these results are illustrated in **Appendix 3**.

Using the velocity string of size 3"1/2 and assuming a constant WGR and constant GOR for the forecasting purpose and the wellhead pressure will remain as an unchanged constraint at 65 bars for both the well HR104 and HR101, the results of liquid loading prediction are shown in **figure (4.6)** and **figure (4.7)** respectively for the well HR104 and the well HR101.

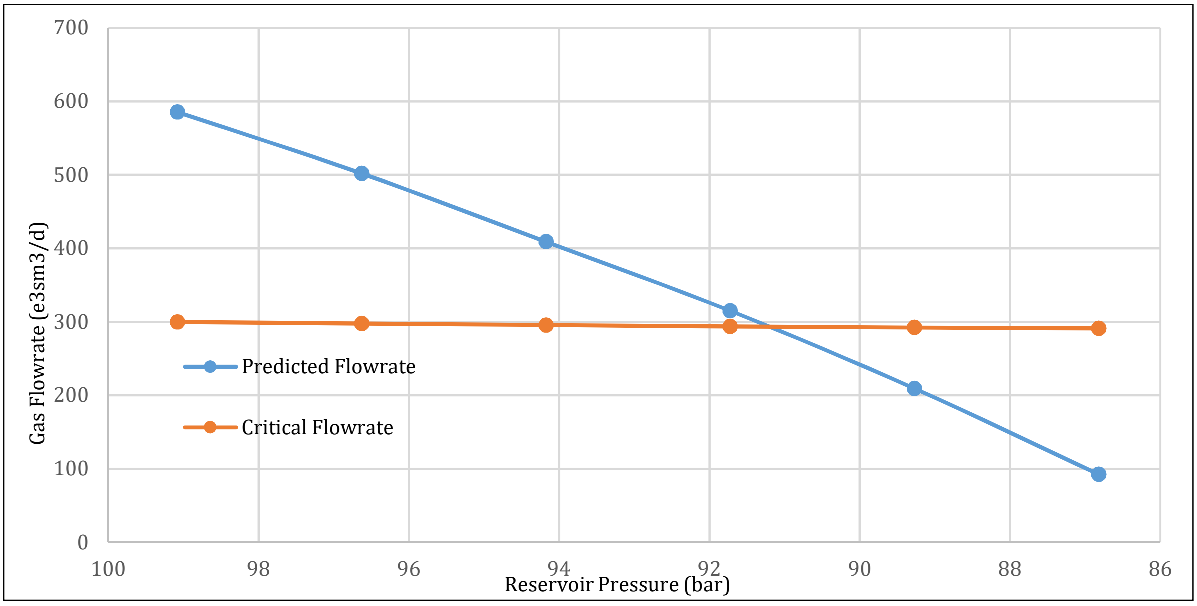

Figure (4.6): Turner Model Prediction Loading for the Well HR104 Using Velocity String

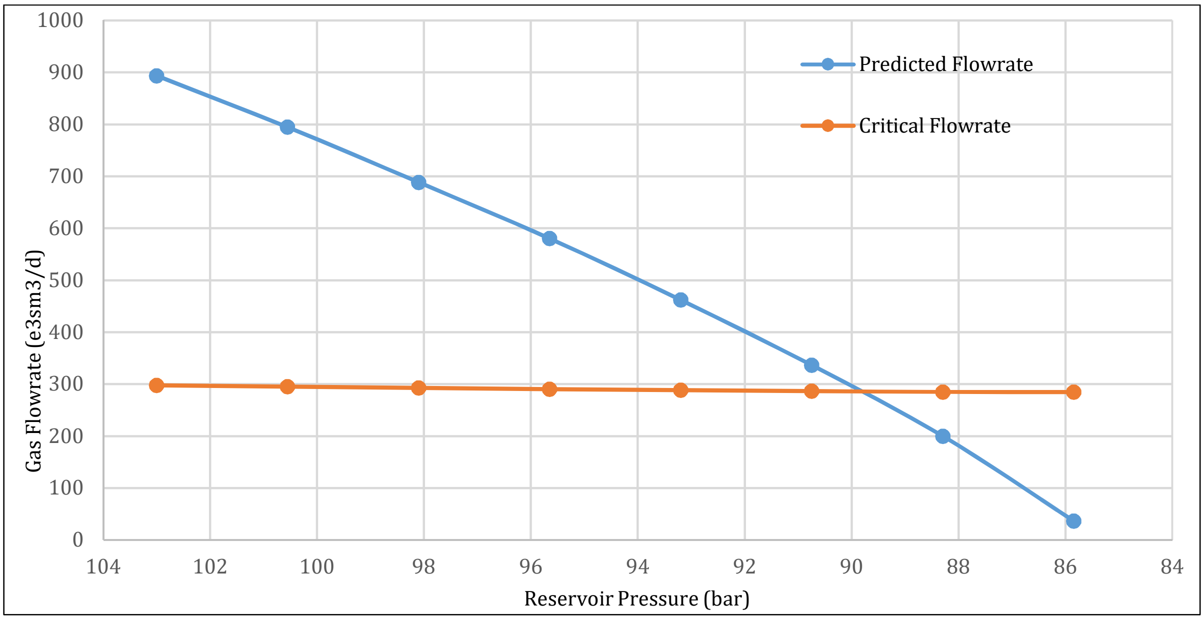

Figure (4.7): Turner Model Prediction Loading for the Well HR101 Using Velocity String

After applied the velocity string of size 3"1/2 in the wells HR104 and HR101, it is noted that the liquid loading will occur at the reservoir pressure of 91.2 bar, which is corresponding to the year 2022 for the well HR104, and at the reservoir pressure of 89.8 bar which is corresponding to the year 2023 for the well HR101. Thus, decreasing the diameter of tubing causes increasing in gas velocity and gas flow rate, so here the problem will occur late compared with the case of wells without using velocity string as described in the previous chapter. Therefore, the use of velocity string works to delay the occurrence of the loading but does not solve it as a final solution.

4.2.4. Advantages and Disadvantages of Using the Velocity String

There are some pros and cons of the velocity string that should be evaluated before proceeding in this direction. Some of the advantages are:

- The installation of a velocity string is a very simple and cheap type of construction compared with the other solutions to the liquid loading problem.
- The installation of a velocity string as an extension of tubing is very simple and cheap (no need of Workover) compared with the decreasing of tubing size (need of Workover).
- Compared with the decreasing of tubing size or the installation of the velocity string up to the surface, the installation of a velocity string as an extension of tubing meets the maintain of the functionality of the SSSV and there is no technical hardware across the wellbore, therefore problems with later services or the like can be avoided.

Some of the disadvantages of the velocity string are:

- Although the use of velocity string will delay the liquid loading, after some time of production it can happen that liquid loading appears and production diminishes or even stops again. So, the installation of the velocity string will be a short-term solution and not a final solution. Also, if the completion is changed to a smaller tubing today, then later it may have to downsize to even smaller tubing.
- Test tools and coiled tubing cannot be run in the smaller tubing and the smaller size velocity string up to the surface.
- If the smaller tubing becomes loaded, then it cannot swab the tubing and may not even be able to nitrogen lift it.
- When the reservoir pressure is quite low and the reservoir is depleting; lift methods should be selected instead of installing a smaller diameter tubing string since a smaller diameter tubing string will become insufficient after a short time.

4.3. The Impact of Boosting to solve Liquid Loading Problem in Hassi R'mel's Gas Wells

In this section, we study the application of Boosting as a remedy to solve the liquid loading problem in the gas wells of Hassi R'mel.

4.3.1. The Decision for the Boosting

The production history of the Hassi R'mel gas field, from his initial exploitation to this day, shows a gradual drop in reservoir pressure. On the other hand, the gas treatment units (MPP) are designed to operate at an inlet pressure above 100 bars. Taking into account these two parameters, boosting is a necessity. For this reason, three stations of boosting (compression) have been implemented (SBN, SBC, and SBS) from 2004; these compressors have been installed between the producing wells and the inlet manifold of the MPP in order to increase the pressure of raw gas to be above 100 bars.

Currently, the inlet pressure of boosting (phase two) is about 56 (kgf/cm^2). Following the depletion of the field and the current inlet pressure of boosting that arrived at its operating limit, a project of boosting phase three is planned in two phases; the first is planned between the end of 2019 and the beginning of 2020 with an inlet pressure of 24 (kgf/cm^2), the second is planned in 2023 with an inlet pressure of 10 (kgf/cm^2). [9]

From the previous, the compression is crucial to all gas well production as it is the primary means to transport and treat the gas. Compression is also vital to deliquification, by lowering wellhead pressure and increasing gas velocity.

4.3.2. The Impact of Boosting on the Liquid Loading

We apply a nodal analysis system for the four wells to evaluate the effect of reducing the surface tubing pressure on the current potential uplift and the future results expected from compression. We assume a constant WGR and constant GOR for the prediction purpose and the reservoir pressure will remain as an unchanged constraint. As the results are similar, the following **figure (4.8)** is an example, for the well HRD023, shows a schematic of the beneficial effect of wellhead pressure reduction by boosting application.

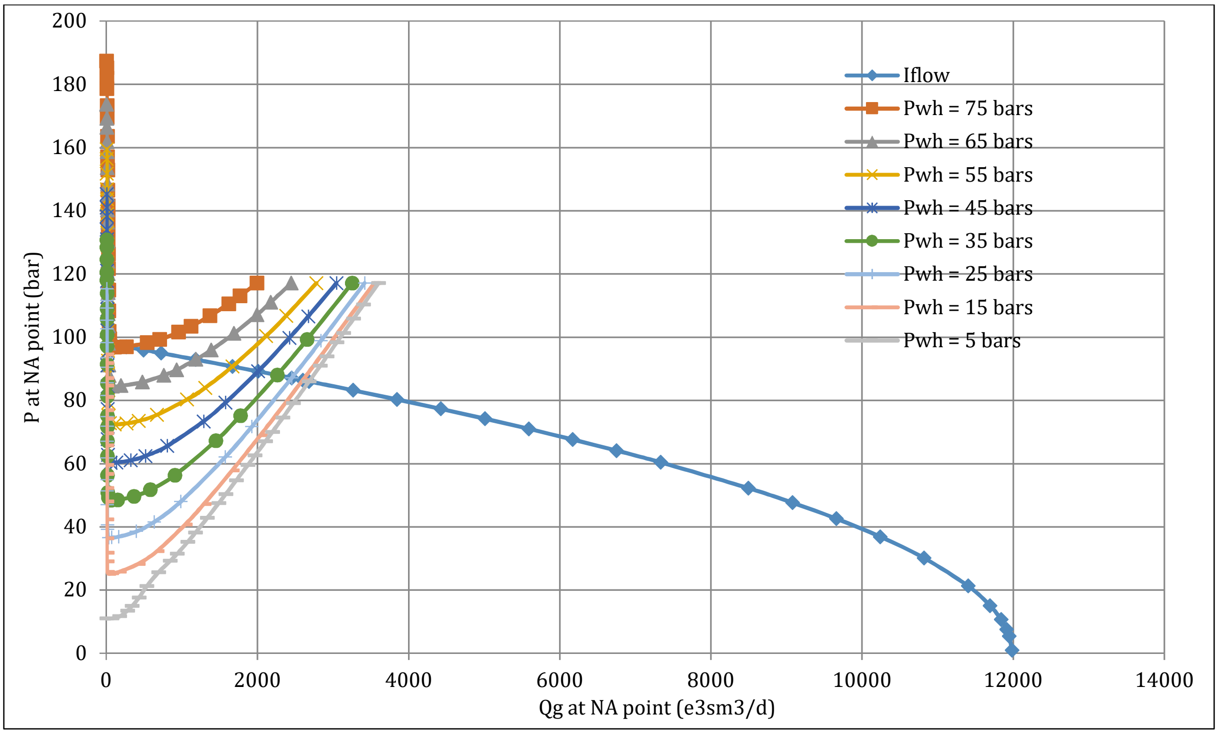

Figure (4.8): Effect of Compression on the System Nodal Analysis for the Well HRD023

It can be seen that the IPR stays fixed, the VLP move down with decreasing wellhead pressure and the intersection shows higher production rates. The boosting lowers the wellhead pressure, increasing velocity and allowing liquids to be unloaded from the well. As the liquids are unloaded the hydrostatic head in the tubing is reduced, substantially decreasing the producing bottom hole pressure resulting in increased production. Therefore it could keep the well free of liquids for a long time without the need for high capital investment.

Besides, **figure (4.8)** shows that the well can become stable with reduced surface pressure. One way to more easily see this is to plot the solution points from the systems nodal analysis well prediction and the critical rate calculated per Turner as shown in **figure (4.9)**.

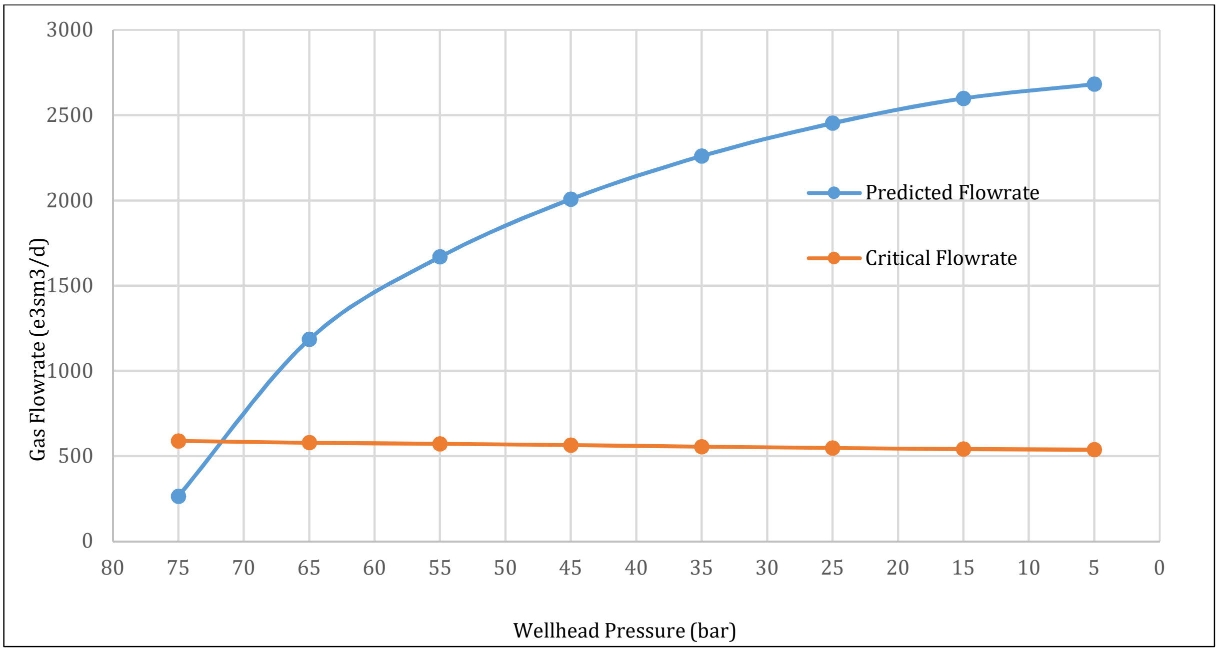

Figure (4.9): The Effect of Wellhead Pressure Reduction on the Prediction and Turner Critical Rate for the Well HRD023

It can be seen in this figure that the wellhead pressure must be reduced to about 72 bars to unload the well; under this pressure, the predicted flow rate is greater than the critical flow rate. However, additional flow can be obtained by reducing the pressure further. Therefore, the wellhead compression extends the life of gas wells, dramatically boosting their production output.

Conclusion

In this chapter, different analytical methods as completion change and artificial lift have been discussed. Among these methods, two techniques have been planned to apply in the Hassi R'mel field; installation of velocity string and boosting application. Keeping in mind that depletion of the reservoir is the main reason behind liquid loading; changing the cross-sectional flow area by installing a velocity string under the end tubing proves to be beneficial for a short time. While, many times compression can be the most economical way to keep wells deliquified, providing higher production rates at lower surface pressures.

Conclusion and Recommendations

Conclusion

The purpose of this study was to identify and predict the onset of liquid loading in gas wells, and to solve this problem by one or more artificial lift methods desired to handle with it (the method of velocity string and boosting). In order to satisfy it, the case study was applied in gas condensate wells of the Hassi R'mel field using the Pipesim software. The following conclusions were made on the basis of this work:

- The liquid loading is inevitable and not always obvious in gas wells when it occurs; if a well is loaded, it still may produce for a long time before his shut-in.
- Most gas wells will have liquid loading occur at some point during the productive life of the well.
- The recognize of the liquid loading is from well symptoms, critical velocity, and/or nodal analysis.
- The main source of the liquid loading in the gas wells of the Hassi R'mel is the saltwater of the formation.
- The main indicator of the liquid loading in the Hassi R'mel field is the lower production rate and the decreasing of the tubing head pressure. If these signs appear, the well will shut-in for a period of time, and when it is re-opened it will produce briefly then dies again. But, if the well is re-opened towards torch (reduction of wellhead pressure), the well will produce for a long time.
- The pose of bridge plug is the most used solution to plug the flooded reservoir to eliminate the water loading at the bottom of the well.
- Based on the Nodal Analysis, the well HR055 and the well HRD023 are loading up. Whereas, the liquid loading is predicted in 2021 for the well HR104 and in 2022 for the well HR101, for the current conditions.
- Predicting the onset of the liquid loading has been the most effective way of managing or controlling its occurrence.
- The most likely location of the initial of the liquid loading is between the end tubing and the perforation (large casing) because of the low gas velocity.
- The tubing inside diameter is the most important variable in determining the critical liquid loading rate and the onset of liquid loading.

- The velocity string (tubing extension) of diameter 3”$^{1/2}$ gives the highest daily gas production; it is a suitable size.
- Using the velocity string, the well HRD023 is unloaded. Whereas, the liquid loading is predicted in 2022 for the well HR104 and in 2023 for the well HR101.
- The use of velocity string works to delay the occurrence of the liquid loading but does not solve it finally; the installation of the velocity string will be a short-term solution.
- Boosting lowers the wellhead pressure, increasing velocity and allowing liquids to be unloaded from the well. Therefore it could keep the well free of liquids for a long time.
- The wellhead compression extends the life of gas wells, dramatically boosting their production output.
- The use of compression to lower the wellhead pressure can be used as a primary artificial lift method or to aid the other types of artificial lift to different degrees.

Recommendations

The following main recommendations are made with respect to future work for the selection of remedial options against liquid loading problem in gas wells of the Hassi R’mel field:

- More data are needed especially the dynamic bottom hole pressure to improve the modeling of the well performance.
- Select a pilot well for the study of the liquid loading.
- For the future completion, selecting the optimum tubing size can be a long term solution for the liquid loading.
- Target the wells that produce water and perform the RST tests in order to plug the flooded reservoir, and perforate the gas zones to increase the gas flow rate.
- If artificial lift is not yet available, extended shut in periods may be needed to deliquefy the wellbore.
- The appropriate artificial lift method can be selected and implemented before the well under goes severe production losses. Therefore, the gas deliverability can be preserved and production loss can be minimized.
- There are other permanent solutions for the liquid loading can be used like: Plunger Lift and Gas Lift.

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Appendix 1

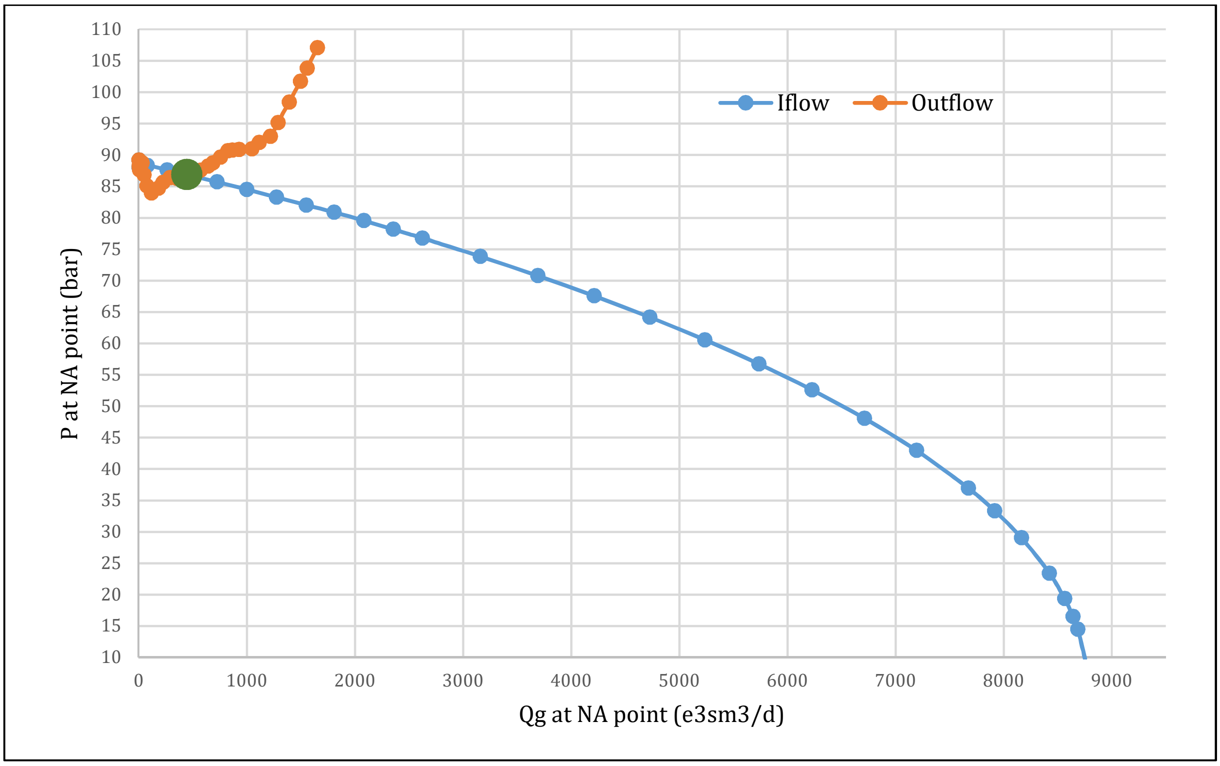

Figure 1: IPR and VLP Curves for the Well HR055

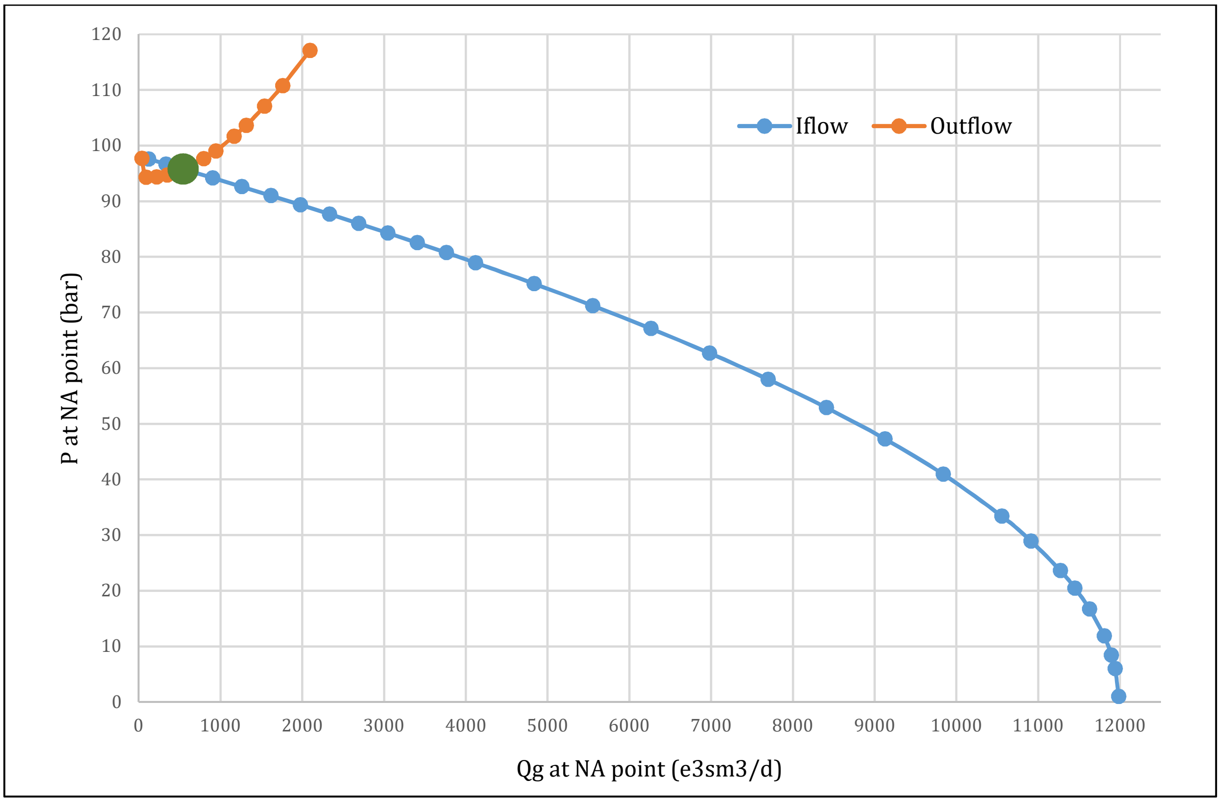

Figure 2: IPR and VLP Curves for the Well HRD023

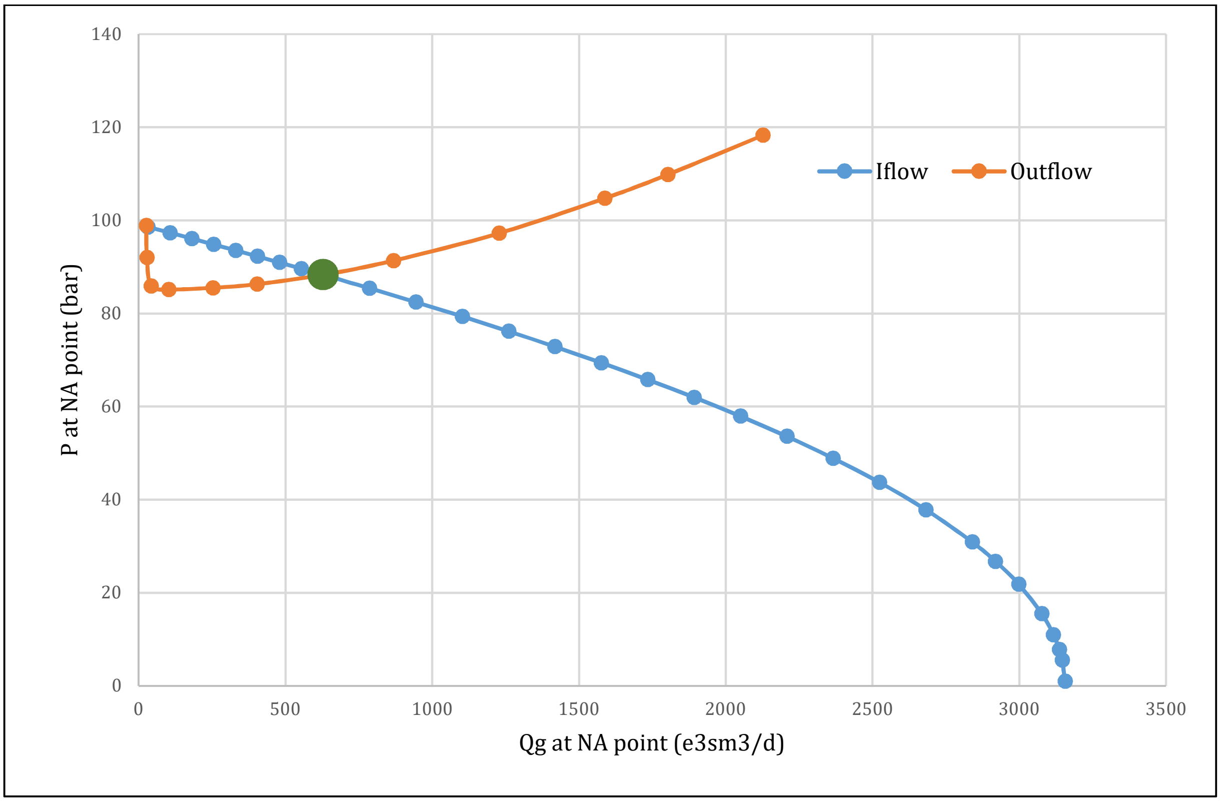

Figure 3: IPR and VLP Curves for the Well HR104

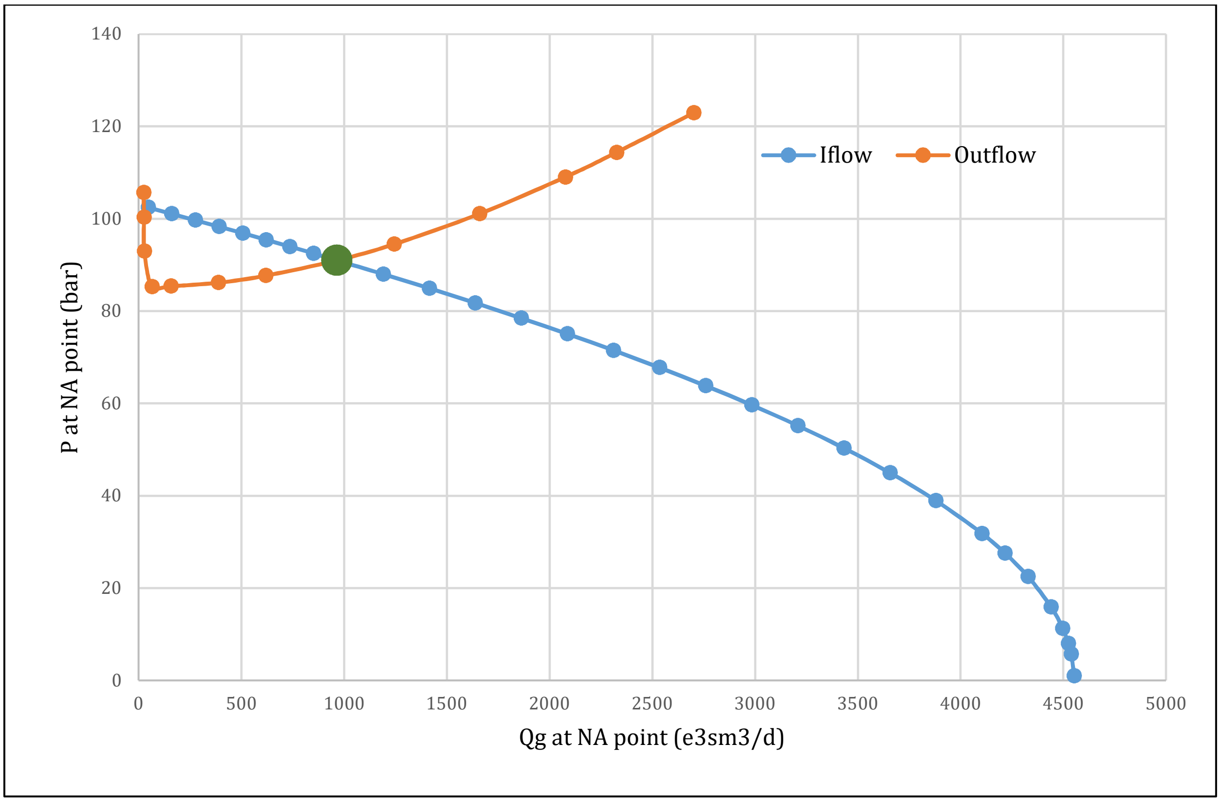

Figure 4: IPR and VLP Curves for the Well HR101

Appendix 2

Table 1: The Loading Status and the LLVR Profile for the Well HR104

Equipement	Elevation (m)	FMV (m/s)	LLV (m/s)	LLVR	Liquid State
Perforation C	-2236.988	4.632301	2.20139	0.47553	Unloaded
	-2145.609	4.676743	2.211237	0.47312	Unloaded
Top Liner 7"	-2101.992	2.455102	2.215558	0.90301	Unloaded
Tubing end	-2080.839	2.460237	2.217571	0.90194	Unloaded
	-2080.504	9.968876	2.217778	0.22261	Unloaded
Siege 4"313	-2080.382	7.750567	2.241797	0.28943	Unloaded
	-2078.065	7.752397	2.242009	0.28938	Unloaded
Siege 4"75	-2077.608	4.967871	2.242143	0.45161	Unloaded
	-1828.8	5.096479	2.247705	0.44132	Unloaded
	-1524	5.25005	2.199387	0.41925	Unloaded
	-1219.2	5.396535	2.016066	0.374	Unloaded
	-914.4	5.53782	1.908828	0.3452	Unloaded
	-609.6	5.664745	1.852872	0.32769	Unloaded
	-304.8	5.787004	1.820466	0.31526	Unloaded
Tubing head	0	5.905045	1.801784	0.30589	Unloaded

Table 2: The Loading Status and the LLVR Profile for the Well HR101

Equipement	Elevation (m)	FMV (m/s)	LLV (m/s)	LLVR	Liquid State
Perforation A	-2208.337	7.099412	2.179156	0.30715	Unloaded
	-2164.994	7.132494	2.184876	0.30653	Unloaded
Top Liner 7"	-2135.002	3.630423	2.188622	0.60326	Unloaded
Tubing end	-2123.603	3.634527	2.190023	0.60296	Unloaded
Siege 4"313	-2123.145	12.00317	2.190574	0.18262	Unloaded
	-2120.859	12.00644	2.190908	0.1826	Unloaded
Siege 4"56	-2120.372	7.169441	2.191234	0.30584	Unloaded
	-2102.663	12.17613	2.193717	0.18029	Unloaded
	-2102.51	12.17632	2.193736	0.18028	Unloaded
	-2102.114	12.55267	2.22997	0.17776	Unloaded
Siege 4"75	-2102.114	7.406926	2.230119	0.30128	Unloaded
	-1828.8	7.63366	2.268251	0.29733	Unloaded
	-1524	7.888485	2.310874	0.29314	Unloaded
	-1219.2	8.141462	2.354037	0.28933	Unloaded
	-914.4	8.403737	2.398152	0.28556	Unloaded
	-609.6	8.668204	2.267996	0.26187	Unloaded
	-304.8	8.934362	2.148563	0.24076	Unloaded
Tubing head	0	9.195616	2.069395	0.22536	Unloaded

Appendix3

Table 1: The Loading Status and the LLVR Profile for the Well HR055 Using Velocity String

Equipement	Elevation (m)	FMV (m/s)	LLV (m/s)	LLVR	Liquid State
Perforation C	-2170.206	1.487266	2.191382	1.47630171	Loaded
	-2152.467	1.491421	2.194811	1.47448587	Loaded
	-2152.223	3.923182	2.194903	0.56055819	Unloaded
	-2148.2	1.492487	2.195691	1.47402253	Loaded
Perforation B	-2141.007	1.603911	2.196911	1.37217159	Loaded
	-2117.415	1.609827	2.201423	1.36992888	Loaded
Perforation A	-2117.415	2.801026	2.199579	0.78598461	Unloaded
	-2095.988	12.00242	2.202769	0.18369236	Unloaded
Top Liner 7"	-2049.993	12.15552	2.209084	0.18189929	Unloaded
Tubing end	-2041.733	12.18377	2.209985	0.18155167	Unloaded
Siege 4"313	-2041.276	4.452641	2.210105	0.49680717	Unloaded
	-2039.082	4.453726	2.210138	0.4966936	Unloaded
	-2038.99	5.243725	2.210146	0.42186537	Unloaded
Siege 4"56	-2038.594	2.877381	2.214516	0.77032507	Unloaded
	-2020.794	2.883949	2.214538	0.76858013	Unloaded
Siege 4"75	-2020.245	2.884372	2.214551	0.76847213	Unloaded
	-1828.8	2.954536	2.201821	0.74594634	Unloaded
	-1524	3.063734	2.139373	0.69907748	Unloaded
	-1219.2	3.174115	2.011759	0.63476427	Unloaded
	-914.4	3.289406	1.929769	0.58781576	Unloaded
	-609.6	3.410392	1.894766	0.5569089	Unloaded
	-304.8	3.540851	1.88442	0.53366498	Unloaded
Tubing head	0	3.679911	1.889475	0.51505255	Unloaded

Table 2: The Loading Status and the LLVR Profile for the Well HRD023 Using Velocity String

Equipement	Elevation (m)	FMV (m/s)	LLV (m/s)	LLVR	Liquid State
Perforation C	-2206.752	2.802987	2.086421	0.74482798	Unloaded
	-2189.988	2.807483	2.088356	0.74432507	Unloaded
Top Liner 7"	-2081.997	12.21695	2.110277	0.17284264	Unloaded
Tubing end	-2019.3	12.34777	2.123046	0.17204625	Unloaded
Siege 4"56	-2018.69	4.5126	2.123387	0.47084351	Unloaded
	-2014.88	4.514129	2.123812	0.47077827	Unloaded
	-2014.515	4.902509	2.123873	0.43349544	Unloaded
Siege 4"75	-2014.393	2.906502	2.129445	0.73310963	Unloaded
	-1998.756	2.910581	2.131227	0.7326958	Unloaded
Siege 4"813	-1998.269	2.910889	2.131358	0.73266308	Unloaded
	-1828.8	2.953457	2.090727	0.70838506	Unloaded
	-1524	3.024254	1.962479	0.64951944	Unloaded
	-1219.2	3.087084	1.796698	0.58281793	Unloaded
	-914.4	3.14102	1.687244	0.53822326	Unloaded
	-609.6	3.184217	1.629376	0.51300006	Unloaded
	-304.8	3.220436	1.593558	0.49636101	Unloaded
Tubing head	0	3.250142	1.568698	0.48443052	Unloaded