NTNU – Trondheim
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Model-based optimization of production systems

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Petroleum Engineering
Submission date: July 2015
Supervisor: Milan Stanko, IPT

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Case Study: Gas-Lift Method

By

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Master's Thesis in Petroleum Engineering

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Abstract

Gas lifted method is one of the artificial lift technique used in the oil and gas industry. This method is applied most in oil well to improve the oil recovery by lowering the bottom hole pressure.

Normally in the field there are multi-gas lifted wells that requires certain amount of gas to be injected to achieve the maximum oil production. Generally the amount of gas available is limited, therefore is has to be allocated per well in the best way possible to achieve maximum oil production in the system. The problem of determining gas lift allocation per well to ensure maximum oil production can be formulated and solved as a mathematical optimization.

The results of the optimisation is a optimum gas injection rate that yield the maximum oil production for group of wells, this is important because excessive gas injected into the well can reduce the oil production and increases operation cost.

For a group of gas lifted wells there are two possible methods to perform the optimisation. Method 1, by assuming that the well operating conditions (i.e. wellhead pressure) of each well in the system will not be affected by the neighbouring wells and using pre-computed gas lift performance curves of each well. In method 2, the case is usually solved using a mathematical optimisation routine and a model of the entire production system.

To achieve the main goal of the present thesis, optimisation for an ideal production network with five gas lifted wells has been modelled in Excel with data generated in PROSPER for the case of method 1 and in GAP optimisation software for the case of method 2. Therefore a deviation between the methods were calculated and presented in percentage for better analyses and observations. Through the results presented in this thesis the value of the total oil production found using method 1 can in some cases be close to the value in GAP optimisation (method 2), but in another hand the injected gas per well differ from each other in the same system. The deviation found for the case of injected gas per well increases proportional with the amount of gas available in the system.

For the optimisation using method 2, three different model schematic were created, and the model without an pipeline showed to be the system with more oil production, due to the location of the separator that does not contribute for the pressure loss in the system. The second model (GAP-2) have the lower production in comparison with all the model, cause by the pipeline length distance (12km) that affect the pressure loss during the production.

In method 1 two different techniques were used for the optimisation, the piecewise-linear optimisation and the curve fitting. The calculation shows that the piecewise-linear has high deviation value compared with the curve fitting technique, being better to use the curve fitting to calculate the optimisation when the constant wellhead assumption is used. Curve fitting techniques two equations were used to fit the gas lift performance curve data (generated in PROSPER), the Alaracón et al. and Rashid et al. The Rashid et al. equation was observed to be the best representative of the gas lift curve in all the scenarios and the deviation tended to be lower than one found using the other equation.

If the number of iteration and time taken for each system to reach the optimum point is considered, the curve fitting technique using Rashid et. al. equation takes less time and iteration number comparing with other techniques in method 1. For the case of optimisation using method 2 those values change in all scenarios and model, is not constant trend.

The study shows that, if a optimisation using method 1 is done for a system with wells having high values of gas injection (more than 10 scf/D) to achieve the maximum oil production, the deviation between the methods (Excel and GAP models) will be more than 10%. This also when the data generated from PROSPER have more than 2000 STB/D as maximum oil production per well. If the data generated containing gas injection greater than zero at the beginning of GLPC is used in method 1 optimisation the deviation can be more than 30% when all wells in the system present the same characteristic.

The deviation calculated between the method 1 and method 2 is lower for the system using the third model schematic in GAP where pipelines were added. The total oil production is lower than the first model and greater than the second model, making the value more approximated to the optimum found in method 1.

In optimisation using method 1 if the wells data from gas lift performance curve present low oil production and gas injection, the value of coefficients in equation of Alaracón and Rashid are almost the same and the deviation calculated using this well will be lower. For wells having the value of coefficient different the deviation calculated will be high, this is the case of well with gas injection greater than zero at the beginning in the gas lift performance curve.

Acknowledgment

First and foremost, I have to thank my at NTNU supervisors, Dr. Milan Stanko and Prof. Michael Golan for the opportunity of being part of the students assisted by them. Extend my thanks to the co-supervisor at University of Dar-es-salaam Prof. Abraham Temu for the assistance given to me during my stay in Tanzania. Without their assistance and dedicated involvement in every step throughout the process, this paper would have never been accomplished. I would like to thank you very much for your support and understanding over these semester.

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For all and everyone I say:

-Thank you-

Contents

List of Figures

List of Tables

Nomenclature

Abbreviations

AOFP	Absolute open flow pressure
ANTHEI	Angola Norway Tanzania high education initiative
ESP	Electric submersible pump
GAP	General allocation package
GL	Gas lift
GLPC	Gas lift performance curve
GLR	Gas-Liquid ratio
GOR	Gas-Oil ratio
IPR	Inflow performance relationship
MD	Measured depth
NTNU	Norwegian university of science and technology
PETEX	Petroleum experts limited
PI	Production index
P_r	Reservoir pressure
PROSPER	Production and system performance
scf	Standard cubic feet
SG	Specific gravity
SQP	Sequential quadratic programming
STB	Stock tank barrel
VLP	Vertical lift performance
UDSM	University of Dar-es-Salaam
WHP	Wellhead pressure
WOR	Water Oil ratio

Symbols

q_o	Produced oil rate
q_g	Gas injection rate

Subscripts

bp	Bubble point
g	Gas
in	Intake
inj	Injection
o	Oil
r	Reservoir
T	Total
wf	Well flow

Chapter 1

Introduction

In the petroleum industry one of the major objectives is to maximise and/or prolong the oil production within the technical and financial limits existent. To ensure that the aim is reached many technologies such as *artificial lift* has been developed.

Different artificial lift methods such as sucker rod pump, progressive cavity pump, gas-lift injection, jet pump and electric submersible pumps (ESP) have been used in most of the fields all over the world to increase the oil and/or gas production rate considered not economical, thus maximising recovery and prolonging field life. For this thesis work, the main focus is production networks with gas-lifted wells.

In most of the cases during the lift process, gas at high pressure is injected into the tubing string, through the gas lift valve at the bottom of the well. The injection can be at fixed or variable points where the gas will be mixed to the fluid coming from the reservoir, resulting in reduction of total pressure losses in the tubing (bottom-hole pressure). This reduction of pressure is due to the light fluid or reduction of the mixture density circulating in the column, therefore large amount of fluid will flow along the production tubing to the surface increasing the oil production. However at some point if large amount of gas is injected the oil production will decrease, this happen when the friction pressure loss increase up to certain point where the gas phase moves faster than the liquid, leaving behind the fluid coming from the reservoir. Therefore, there is optimum limit of injection for a particular well, where the oil production start to decline or at maximum oil production point.

Any artificial lift system can be divided into two main parts when the design and the analyses are taking place. The first is the inflow performance relationship (IPR), which represent the ability of the reservoir to deliver fluid to the production tubing. The second includes the entire piping system and artificial lift system itself, so it is possible to determine the vertical lift performance (VLP) for a certain wellhead pressure, afterwards the flow rate of a well can be known by the intersection between the IPR and VLP curve.

The final choice for the lift equipment and method in most of the case is influenced by many reasons as corrosion, sand and solids production, well deviation angle, oil viscosity and gravity, cost, surface facilities, location and others. However the main factors are the production rate, down hole flowing pressure and the gas-liquid ratio.

The primary constraint when gas-lifted method is chosen to boost up the fluid to the surface, is the total amount of gas available to be injected into the well that in some cases is insufficient or limited. Thus, it is necessary to allocate the amount of gas in some optimal way that yields the maximum oil production from the field. The optimum allocation process is a challenging problem that has been addressed extensively in the past in many studies. It constitutes an optimisation problem that can be solved in principle, using simple mathematical optimisation techniques such as the simplex (linear programming) method and equal slope,and others much more complex as sequential quadratic programming (SQP).

For a group of gas lifted wells producing through the same surface, depending on the conditions of the network and the piping layout, there is usually hydraulic interdependency. That is what changes in the operating conditions of one well and will probably affect the pressures conditions and production rates of the rest wells in the network. For this it is possible to perform a model-base optimisation into two different methods:

1. Using the relationship between the gas injected and the oil produced, denominated as gas lift performance curve for each well. This curve is calculated without taking into account the effect of other wells.

2. Perform a full optimisation using a software without using the gas lift performance curve.

The first method use the individual gas lift performance curve, calculated assuming the constant wellhead pressure. The curve can be fitted to an equation or use linear interpolation between the points and execute mathematical optimisation.

On the other hand the second method employs a numerical model of the production system where mathematical optimisation is performed using an algorithm, and this require multiple model evaluation an example of this, is GAP software developed by the petroleum experts limited (PETEX). This method is sometimes expensive and challenging in the petroleum industry, specially for systems with hundreds of wells.

This thesis work is an extension of the specialization project, that carries the model-based optimisation done using:

a) Gas lift performance curve equation fitting and non-linear optimisation;

b) Linear interpolation in gas lift performance curve and linear optimisation;

c) Model-based optimisation in GAP software.

In the end a comparison aimed to see if the optimisation using method one is a good approximation of method two (GAP) was taken. Additional document file is provide with the information about the number of iteration and time taken for each method used in this study. Also for the case of deviation calculated for gas injection per well found in both methods.

1.1 Project Main Objective

The main objective of the thesis work is to estimate and compare the maximum oil production and the allocation of gas lift for a system of gas-lifted wells by performing the optimisation using individual well performance curve and model based optimisation.

1.2 Specific Objectives

The specific objective of this project are:

a) Understand how to generate the GLPC for different conditions;

b) Identify the behaviour of the curve for different wells layout;

c) Perform optimisation using GLPC in the piecewise linear optimisation;

d) Perform optimisation using GLPC fitting and non-linear optimisation;

e) Perform optimisation without the GLPC in GAP software;

f) Compare the optimum oil production obtained in different methods.

1.3 Project Outline

The present thesis work contain 6 chapters. In the first chapter a brief introduction is presented to give a general view to the reader to know what the report will talk about, this includes the main and specific objectives of the work.

The second chapter involves a review of the literature in the relevant topics to this study. This part of the thesis was meant to understand the fundamentals and the physics of the artificial lift systems giving a special attention in gas-lift well system. An overview of gas lift was carried where classification, principle, advantages and disadvantage were described to give more knowledge about this artificial lift method. Figure 1.1 presents all threads in the first part that are also presented in Chapter 2.

In addition, the familiarization with the PETEX software: PROSPER and GAP was done for optimisation part in the work.

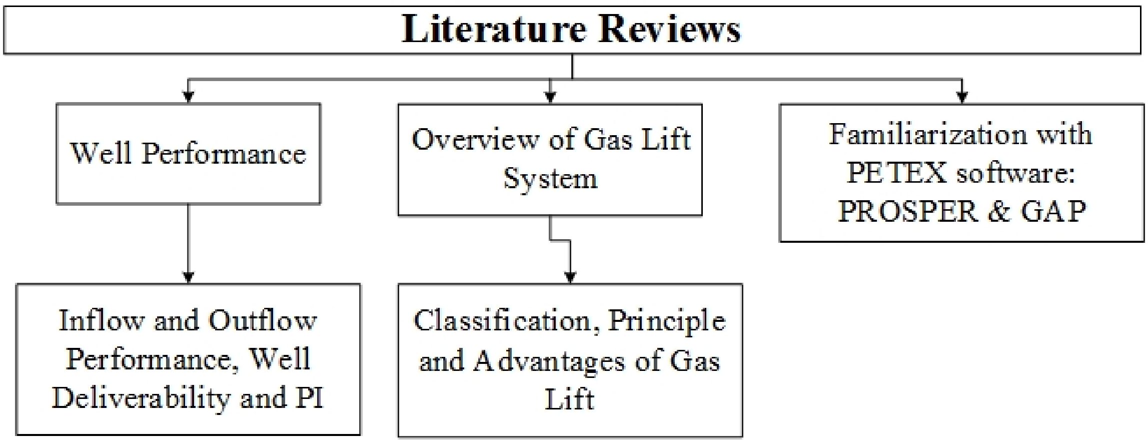


Figure 1.1: Subject Oriented Literature Review

The optimisation in gas lift well systems was carried out in Chapter 3. The chapter explains the theoretical part of the optimisation used to achieve the aim of the thesis (Figure 1.2).

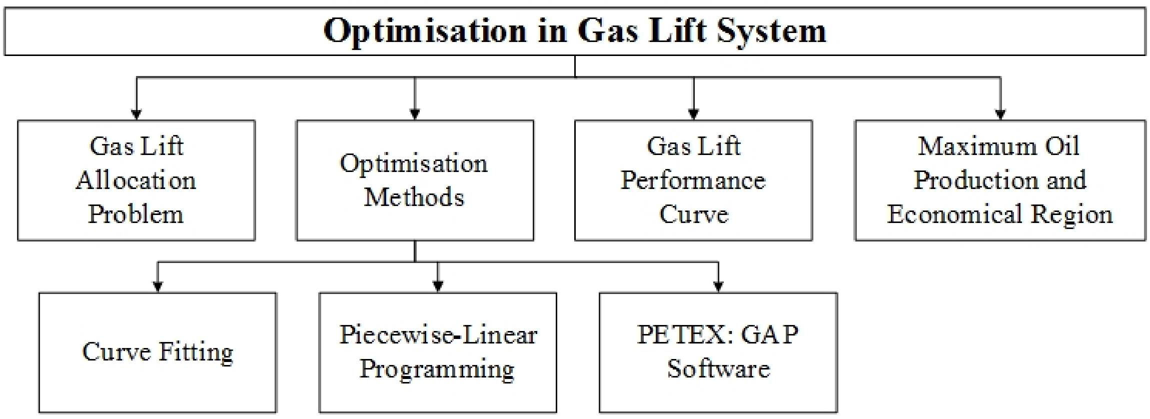


Figure 1.2: Optimisation of gas lift system

In chapter 4 the methodology (Figure 1.3) used to perform the objectives is presented by using the theoretical part explained in the previous chapter.

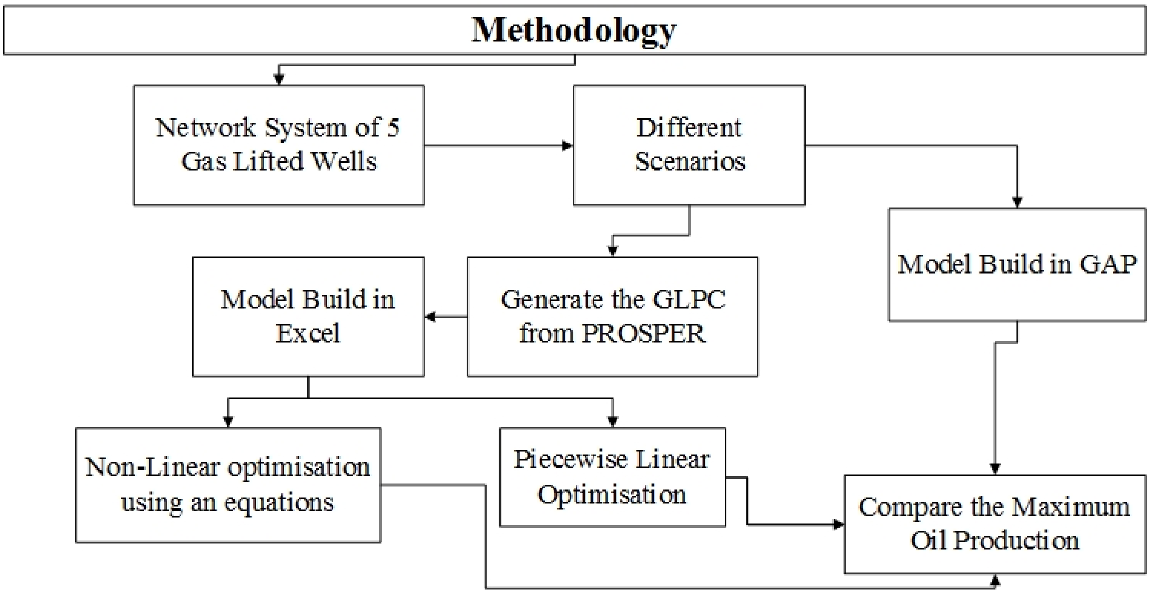


Figure 1.3: Methodology procedure optimisation

In Chapter 5 results of the simulation done in Excel and GAP are presented and discussed. Different cases and scenarios were created to identify when the values of the total oil production are close to each other using different optimisation methods.

Lastly in Chapter 6 the conclusion and recommendation for the thesis are presented.

Chapter 2

Literature Reviews

2.1 Wells Performance

For production optimisation in the gas lift well system, it is necessary to have the conceptions of inflow and outflow (vertical lift) performance of the wells to see how the well behave for a specific characteristics and conditions. In the following section some relevant theoretical concepts that have been considered necessary for the thesis work are presented.

2.1.1 Inflow Performance Relationship

Inflow performance relationship (**IPR**) or *backpressure curve* (used by the engineers dealing with gas wells) is the ability of the reservoir to deliver the fluid into the wellbore or production tubing. With IPR is possible to define how much fluid can flow from the reservoir into the wellbore at given conditions.

The simplest and most widely used IPR equation is the straight-line. The IPR (Figure 2.1) represents the directly proportionality of the rate with the pressure drawdown (difference between the reservoir pressure and the wellbore flowing pressure) assuming the fluid in the reservoir is undersaturated oil .

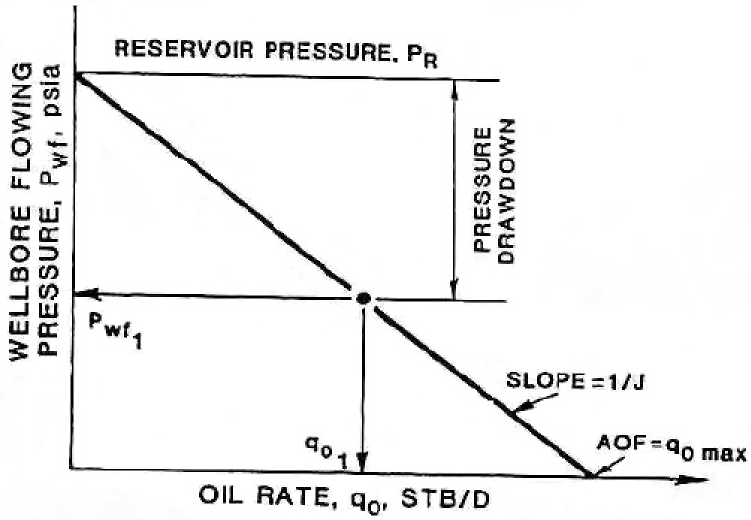


Figure 2.1: Straight-line IPR. [2]

Several equations have been developed so that the saturated oil or two phase flow can be represented. In 1935 Rawlins and Schellhardt introduced the first mathematical expression known as a back-pressure equation, commonly used in gas reservoir.[3]

The equation (2.1) can be afterwards represented as a graph (Figure 2.2).

$$q = C(p_r^2 - p_{wf}^2)^n \tag{2.1}$$

Where C is the inflow back pressure coefficient and n is the back pressure exponent that ranges between 0.5 and 1.

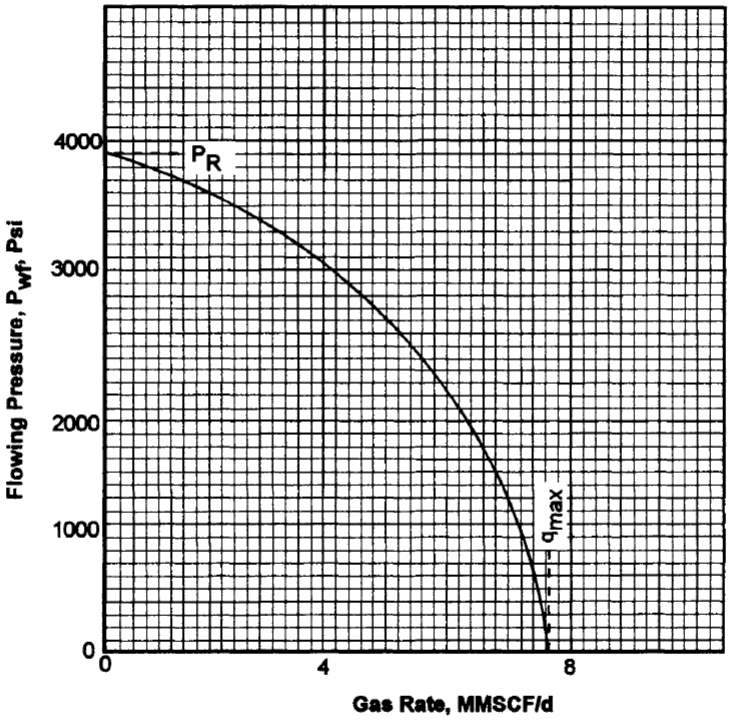


Figure 2.2: Inflow performance relationship for a gas reservoir.[4]

Some factors as rock properties, fluid properties, reservoir pressure, well geometry and well flowing pressure can affect the nature of the IPR curve (Figure 2.3).

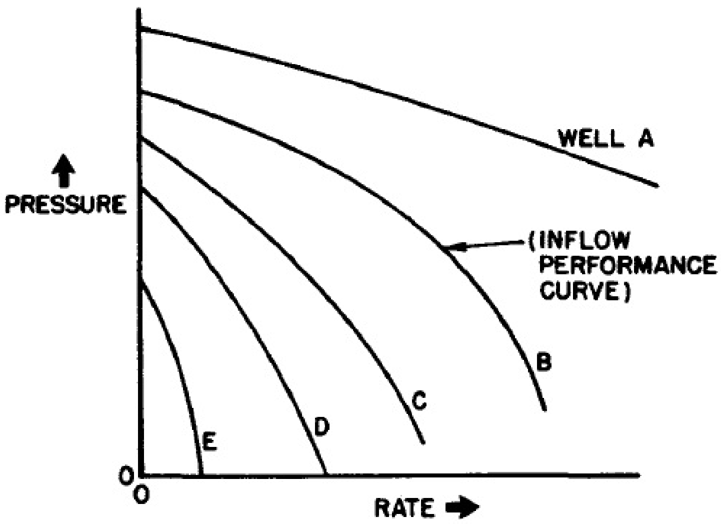


Figure 2.3: Typical inflow performance curves. [4]

2.1.2 Vertical Lift Performance

Vertical lift performance (VLP) is the ability to deliver the fluid to the surface, from the bottom of the well at required wellhead pressure. With VLP curve it is possible to define how much fluid can be lifted by the well at given operation conditions.

As the fluid flows through the production string to the surface, the pressure drop may occur due to gravity, acceleration and friction factor. A simple and accurate equation for a vertical flow of dry gas wells has been recommended by Golan and Whitson (1995).[2]

$$q_g = 200,000 \left[\frac{sD^5(p_{in}^2 - e^s p_{wf}^2)}{\gamma_g TZHf_M(e^s - 1)} \right]^{0.5} \tag{2.2}$$

Where:
q_g = gas flow rate, scf/day
Z = average gas compressibility factor
T = average temperature, $^\circ$ R
f_M = Moody friction factor
γ_g = gas gravity, air=1
p_{in} = flowing tubing intake pressure, psia
p_{wf} = flowing wellhead pressure, psia
H = vertical depth, ft
D = tubing diameter, in
$s = 0.0375\gamma_g H/TZ$.

In cases of gas well assumption that the flow is turbulent, the friction factor results in the following expression:

$$f_m = 2\log[3.7/(\varepsilon/D)]^{-2} \tag{2.3}$$

Where ε is the absolute pipe roughness and $\varepsilon = 0.0006$in for most commercial pipe. The friction factor in equation 2.3 is the best fit for the fully turbulent region of the Moody diagram and is sufficient accurate for most engineering calculations.[2]

Like IPR some factors also affect the nature of the VLP curve such as production rate, well depth, Gas-Oil ratio (GOR), Gas-Liquid ratio (GLR), tubing diameter and Water-Oil ratio (WOR). Figure 2.4 represents the comparison for rate of different lift methods properly that can change with the condition of the well, and the intersection of each VLP with the IPR curve determine the flow rate for a particular lift method. The procedures for preparation of these VLP curves has been presented by Agena.[5]

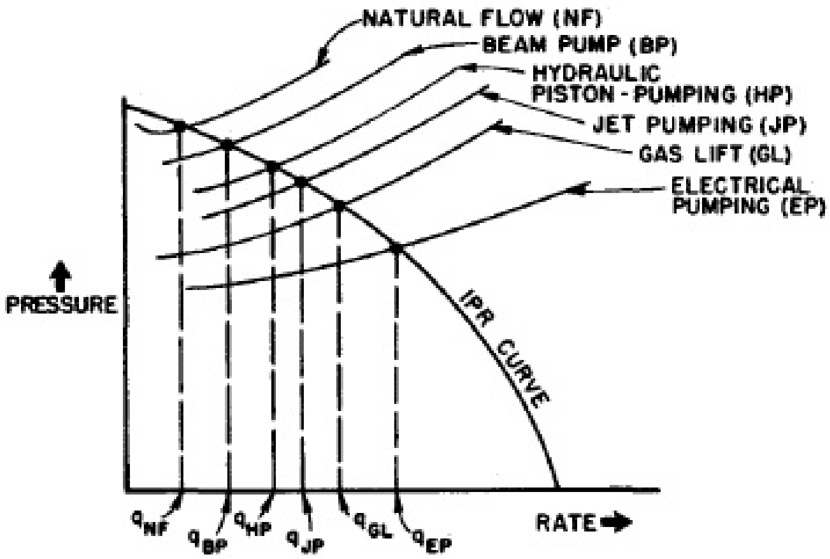


Figure 2.4: Well Deliverability using different artificial lift methods.[4]

Analysis of a VLP of a well is an important part of the well design. It allows selecting the well completion correctly corresponding to lifting methods and to evaluate wells performance.[6]

2.1.3 Well Deliverability

Well deliverability is the stable rate that a particular well can produce, resulting of the combination of the IPR and VLP, where the intersection of the curves is the operation point or natural flow point (Figure 2.5).

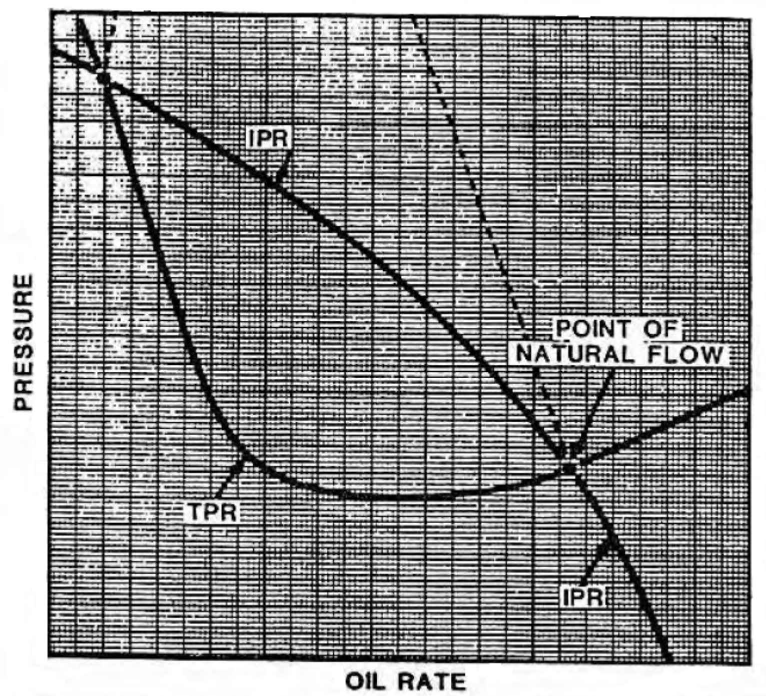
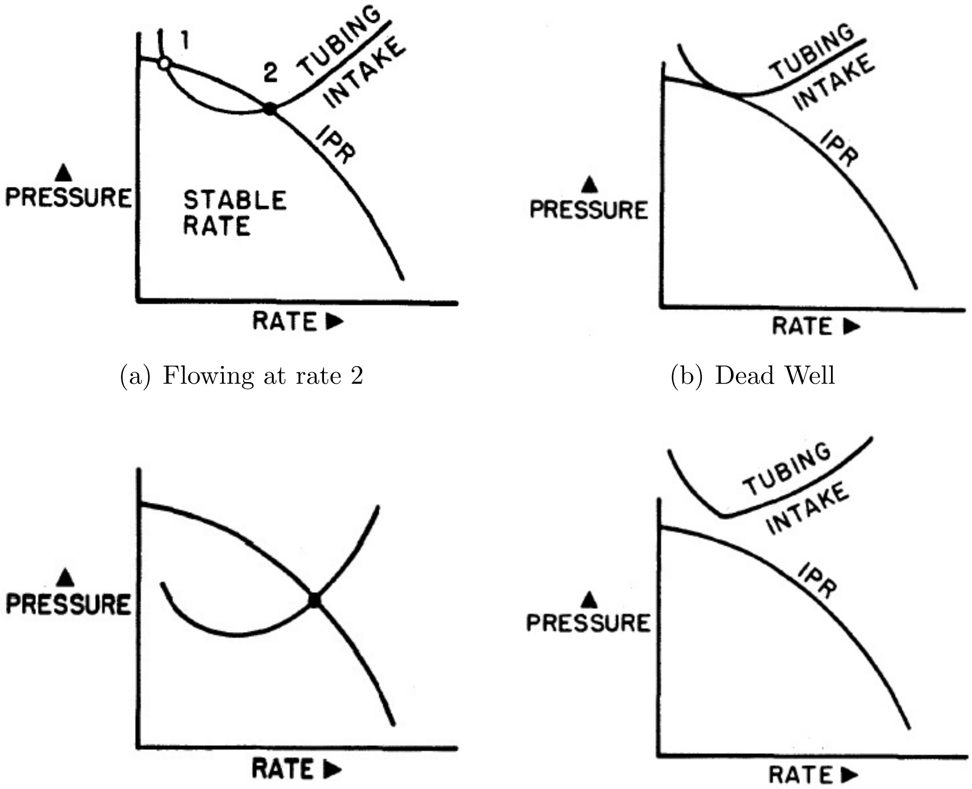


Figure 2.5: Natural flow condition [2]

In Figure 2.6 some examples of well deliverability that can be found in the fields are presented. The curve changes with the condition in the field from there it is possible to see if it will be necessary to apply some methods to ensure that the well will not be dead after a couple of years.



(a) Flowing at rate 2

(b) Dead Well

(c) Stable flow rate

(d) Dead well

Figure 2.6: Examples of well deliverability.[4]

2.1.4 Productivity Index

Productivity index (PI) is one of the important characteristics of a well inflow performance [6]. It is also defined as the flow rate per unit of pressure drop. Dependent of the reservoir and fluid properties, PI serves also to indicate the potential production of the well.

$$PI = \frac{q}{(\bar{p} - p_{wf})} = \frac{2\pi kh}{\mu B} \frac{1}{ln(r_e - r_w) + S} \tag{2.4}$$

Where:
$\bar{p}$ = average reservoir pressure, psig
k = Permeability, md
q = Surface volumetric rate, STB/D
h = Thickness, ft
r_e = Drainage radius, ft
r_w = Wellbore radius, ft
S = Skin factor
B = Formation volume factor, bbl/STB
μ = Fluid viscosity, cp
p_{wf} = Well flowing pressure, psia

Once the PI is known, the equation can be re-arranged to determine the deliverability rate straight forward:

$$q = PI(\bar{p} - p_{wf}) \tag{2.5}$$

The equation (2.5) is only valid for a well with the reservoir pressure (p_R) below the bubble point pressure (p_{bp}). For well with the p_R above the p_{bp}, i.e., saturated reservoir or gas wells, the relationship is not as straight forward. In these situations either an IPR (for oil) or absolute open flow (for gas) analysis should be performed.

2.2 Gas Lift System

Gas lift (GL) is a lifting method that consists in injecting compressed gas at the bottom of the well through the casing annulus or production string, in order to reduce the pressure drop in the column by reducing the density of the fluid and making the well produce a desired rate of oil.

As one of the most common artificial lift employed all over the world, gas lift injection is required when the reservoir pressure us not enough to maintain economical production rates. The typical general GL system is shown in Figure 2.7.

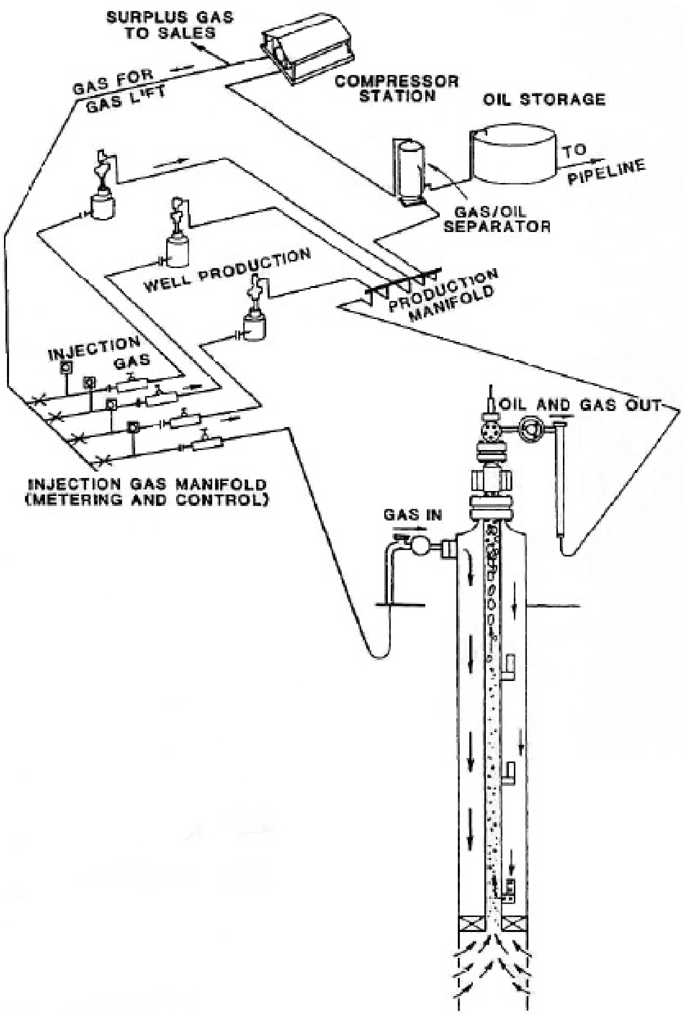


Figure 2.7: General gas lift system.[2]

2.2.1 General Classification of Gas Lift

The oil world has two different ways of lifting the oil or gas to the surface, by using the continuous gas lift and the intermittent gas lift (Figure 2.8).

I. **Continuous gas lift** - is injected continuously in the casing annulus. Recommended for a well with high bottom hole pressures (BHP) and high volume (high PI) and where major pumping problems will occur.

II. **Intermittent gas lift** - is injected periodically into the annulus of the well. Recommended for a well that produces low volumes due to low BHP or low PI.

The system allows the fluids to accumulate in the column, which is quickly displaced to the surface by the gas that have been injected and controlled by the gas lift valve located at the bottom of the well under the fluid accumulated.

The frequency of gas injection is determined with the amount of time it takes for the fluid to enter the wellbore and tubing plus the duration of the gas injection required to displace it to the surface.[6]

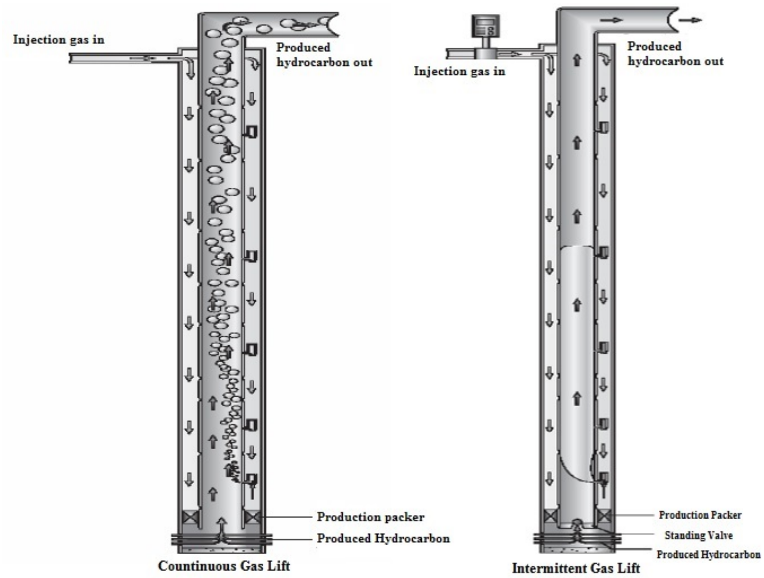


Figure 2.8: General classification of gas lift

2.2.2 Principle of Gas Lift

When the well does not have enough energy, the IPR and VLP do not intersect and the production stops. In order to avoid this, compressed gas is injected into the casing through the valve at the surface and flows from the annulus to the production tubing through a injection valve close to the bottom of the well. Therefore the density above the injection point decreases, then the gas expanded in the tubing will push the liquid ahead, which further the fluid column weight will also be reduced. Displacement of liquid slugs by large bubbles of gas act as piston to push the produced fluids to the surface, this causes liquid to flow to the surface.[6]

For the well to be able to produce the maximum or the desired yield of oil, basic requirement as a sufficient adequate and good-quality of gas should be injected with enough pressure at the appropriate place and rate where the flow system exists. Suppliers are therefore needed throughout the producing life of the field and the injection gas may come from production operation or outside sources. Often sufficient supply and pressure are available from the high separator pressure; if the available operator pressure is not high enough a compressor will be needed.

Figure 2.9 represents the conventional GL, where it is referred to the gas injection depth, gas injection rate, surface injection pressure and production rate.[7] Note that oil production by gas lift can be controlled by changing gas volumes, injection depth, wellhead pressure and tubing size.

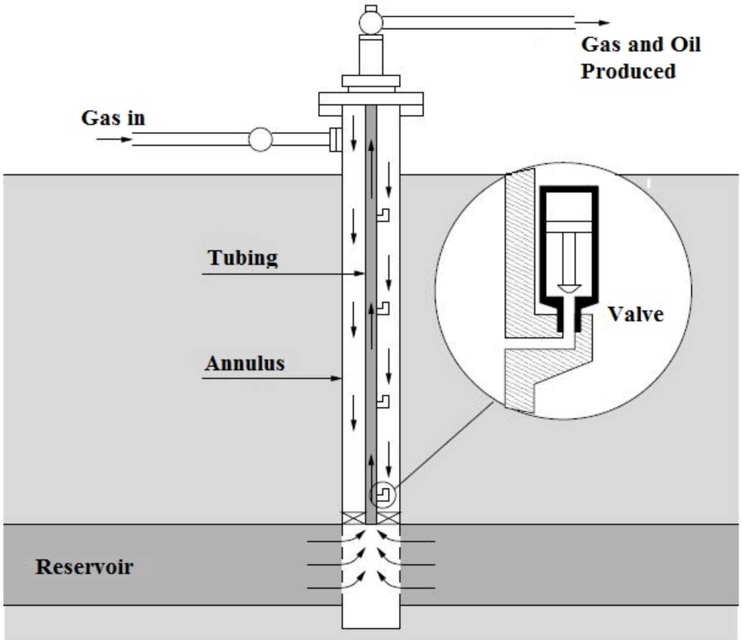


Figure 2.9: Simple gas lift schematic [2]

2.2.3 Advantages and Disadvantages of Gas Lift

As a method to lift the fluid to the surface facilities, gas lift have advantages and disadvantages mentioned in the Table 2.1.

Table 2.1: Advantages and disadvantages of gas lift method. [2]

Advantages	**Disadvantages**
Can produce high rate from high-productivity wells	High initial investment
Flexible,easy to change rate	Limited reservoir pressure drawdown
Can handle large volume of solids with minor problems	Some difficulty in analysing property without engineering supervision
Unobtrusive in urban locations	Gas freezing and hydrate problems
Power sources can be remotely located	Problems with dirty surface lines
Easy to obtain downhole pressures and gradients	Not efficient for small fields or one-well lease if compression equipment is required
Lifting gassy wells with no problem	Cannot effectively produce deep well to abandonment
Sometimes serviceable with wireline unit	Difficult to lift emulsions and viscous crude
Crooked holes present no problem	Not efficient in lifting small field or one-well leases
Corrosion is not usually as adverse	Casing must withstand lift pressure
Applicable offshore-platforms and subsea completions	Safety problem with high pressure gas

Chapter 3

Optimisation in Gas Lift Well System

In the petroleum industry there are many factors and process that must be optimised before and during the life field. For a gas lifted wells system there is usually a limited amount of gas available for injection and it is desirable to allocate it in such a manner that the gas injected will yield the highest oil production possible.

In the gas lifted wells system the problem of optimising typically uses the economical objective function which aims to:

- Maximise the oil production
- Maximise the profit
- Minimise the production cost

In this chapter some important concepts about the optimisation in gas lift network system is considered.

3.1 Mathematical Allocation Problem for Gas Lift System

For a operating using some artificial lift, an optimisation method is indispensable to prevent the inappropriate use of available resources. Optimisation normally is composed by the objective function and the constraints function. Both of them can be constructed in easy or sometimes difficult ways depending on the circumstances. The choice of the objective function is one of the important steps in optimisation and a bad choice make the work meaningless. In the present study the objective function in the gas lift system during the allocation of the gas injected rate is to maximise the total oil production rate from the gas lift wells system using the amount of gas injection as the constraint.[8]

Other constraints that are considered significant in gas lift application include compressor operation limits (maximum speed, horsepower, surge/stonewall, clearance volume limits for reciprocating engines, etc.), production ceiling contracts, water handling facilities (especially offshore), and allowable operating pressures.[9]

The problem of gas allocation optimisation can be formulated mathematically as follows:
Maximise non-linear function of total oil production for a network well system

$$Q_{oT} = \sum_{i=1}^{n} q_{oi} = f(Q_g) \tag{3.1}$$

The total oil production Q_{oT} which is the sum of the individual oil production rates, q_{oi}, can be considered as a function of the flow of gas injected, Q_g, where $Q_g = (q_{g_1}, \cdots, q_{g_n})^T$ is the n-dimensional vector. Equation (3.1) is subject to the following constrains:

$$Q_{gT} = \sum_{i=1}^{n} q_{gi} \leq Q_{g,\,\text{Available}} \tag{3.2}$$

$$q_{gi} \geq q_{gi,\,\min} \tag{3.3}$$

$$q_{gi} \leq q_{gi,\,\max} \tag{3.4}$$

$$q_{gi} \geq 0 \tag{3.5}$$

Where i = number of well 1, 2, $\cdots$, n.

The constraints defined by the Equation (3.2) indicates that the sum of the individual gas injection rates should be less than or equal to the total gas available for the system.

Equation (3.3) and (3.4) ensure that each gas injection rate must not be less than the minimum and greater than the gas injection rate corresponding to the maximum individual oil production rate. Therefore, the gas injection rates should always satisfy the set of constraints defined by Equations (3.2) - (3.4) during the optimisation process. Other constrains can be added in the future to the optimisation technique, such as water cut and minimum economic performance for each well.

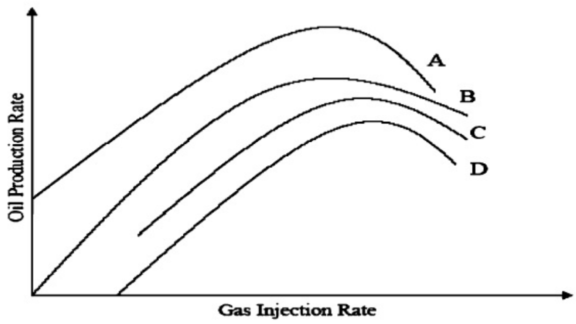
3.2 Gas Lift Performance Curve

The aim of the gas lift system is to deliver the fluid at the wellhead pressure while bottom-hole pressure is maintained lower enough so that the fluid flows easily to the surface. Therefore larger amount of fluid will flow along the production tubing and the gas will lower the oil production, due to the effects of friction pressure loss and acceleration in two phase flow.

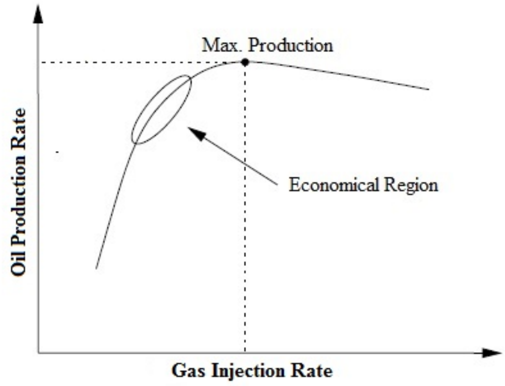
The bottom-hole pressure will increase up to certain point where the gas phase moves faster than the liquid, leaving behind the fluid coming from the reservoir. This will also cause low amount of liquid flowing though the tubing. The phenomenon results in a relationship between the gas injection rate and the oil production rate or what is called *gas lift performance curve* (GLPC) and is essential for optimisation.

The GLPC can be obtained numerically by simulation as the nodal analysis or by measuring the rate of gas injection and the rate of oil production in oil field.[10]

In Figure 3.1(a) some of the typical forms for a GLPC are represented, where the curve A is for a well with an uneconomic oil production rate that gas lift leads to increase in oil rate, and the well is capable of producing naturally. Curve B is related to a well that cannot produce without gas lift system. Curve C and D behave as well not producing without an initial amount of gas, but at this point, well C has a value for oil production rate.[11]



(a)



(b)

Figure 3.1: Typical Forms of Gas lift performance curve [11]

The optimum limit of gas available to be injected into the well should be used to achieve the maximum oil produced. This limit can be economical, where the value of the injected gas does not exceed the price of the extra oil produced discussed by *Kanu et al.* [12] and presented in Figure 3.1(b).

When some points of the curve are known or may be obtained from the field tests, some methods of tuning the curves and fitting model are used to approximate the oil production at the surface as a function of the gas injected into the well.

3.3 Maximum Production and Economical Region

The analysis of the GLPC (Figure 3.1(b)) shows that the oil production has a quick increase at the beginning of the curve with the injection of gas due to the density factor in the column that affect the gravity pressure lost. After sometimes opposite situation is visible where any injection of gas into the well result in less oil production at the surface, where the friction factor is greater than the density. With this it is possible to conclude that, GLPC have two important points to be take in consideration.

The maximum point is the one which any increase in gas injected does not increase the oil produced and with this the oil production start to decrease. This limit or maximum point of oil production is achieved when the derivative of the function in the performance curve is equal to zero.

$$\frac{\partial q_{op}}{\partial q_{gi}} = 0 \tag{3.6}$$

The economical region is where the outputs from gas lift maximise the revenue of the well in production. To find the economical point for the gas lift system, a tangent line should be determined in the economical region, where the tangent curve is the economical region.

Conceptually, the optimum economical production value is reached by the time that additional earnings for the extra oil produced does not compensate the expenses in compress the gas to inject into the well. The Equation (3.7) represent the time at which this is achieved.

$$\Delta q_{op}(P - C_{ext}) = \Delta q_{gi} C_{gi} \tag{3.7}$$

Where:
C_{gi}= Cost for compressing the gas;
C_{ext}= Cost to produce the oil;
P= Oil price.

Therefore, there are two possibilities for solving the optimisation program for gas lift, one where the objective is on maximising the oil production and another on the maximum profit or minimise the expenses. The choice of maximising the profit seems more obvious, but this choice may not be so simple to implement, because it requires the estimation of the cost of compressing gas.

Figure 3.2 illustrates the application of the maximum rate approach for the simple case of two wells. A procedure formulated by the Clegg (1982) [2] suggest that maximum total production from the two wells is the sum of the rates q_{o1} and q_{o2}, where the two performance curves have equal slopes $m_1 = m_2$ and the total available injection gas equals $q_{g1} + q_{g2}$.

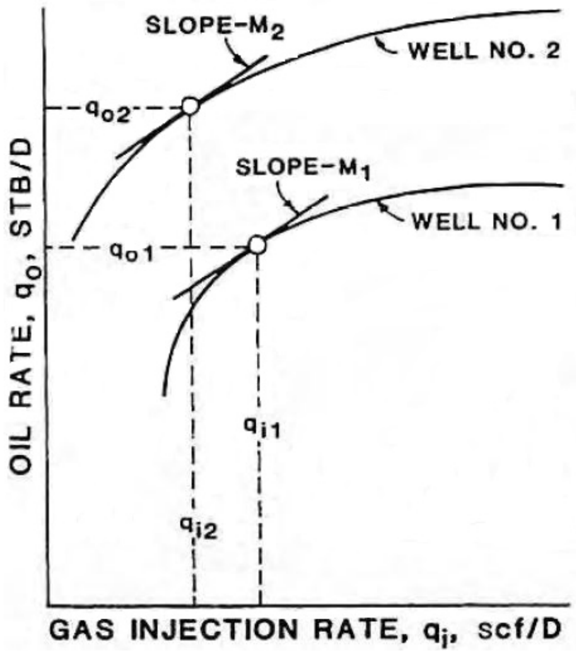


Figure 3.2: Gas allocation between wells for maximum production with limited gas-injection rate.[2]

For this discussion wellhead pressure is assumed to be constant, the assumption is valid if the wells are near to the production separator or if the separators are working at constant pressure.

3.4 Optimisation Method

For a gas lift optimisation problem there is two main methods used to solve this problem. The first one is using the individual well performance curve and another without using the performance curve (model-based optimisation). For this thesis work the methods were used to calculate the maximum oil production for a particular system.

3.4.1 Optimisation using Individual Gas Lift Performance Curve

This optimisation was done using two different methods, a non-linear function using a curve fitting technique and linear function using a piecewise-linear optimisation.

3.4.1.1 Curve Fitting Technique

In subsection 3.2 it was mentioned that the GLPC can be obtained from numerical simulations, and when only some points of the curve are known or may be obtained from field experiments, methods are employed to adjustment of the curve. For classical optimisation problems the GLPC could be approximated by the third-order polynomial equation. But the model is considered more easily treatable, and has large error based on least squares techniques.

$$q_{op} = a_0 + c_1 q_{gi} + c_2 q_{gi}^2 + c_3 q_{gi}^3 \tag{3.8}$$

Later on Alarcón et al.[13] made a comparative analysis of the mathematical curve proposed for the GLPC using the polynomial model, ending with a proposed curve that is represented by second-order polynomial plus a logarithmic term. It was discovered that the model is more accurate than the third-order polynomial, although it has an important disadvantage. This model can cover discontinuous points of the GLPC but fails to match the trend of curve beyond the maximum point. [11]

$$q_{op} = c_1 + c_2 q_{gi} + c_3 q_{gi}^2 + c_4 Ln(q_{gi} + 1) \tag{3.9}$$

Where c_1, c_2, c_3, c_4 are the constant that characterize the well.

Another representation of the GLPC was proposed by Nakashima and Camponogara[14], by using the composition of two exponential terms:

$$q_{op} = \alpha_1(2 - \mathrm{e}^{-\beta_1 q_{gi}}) - \alpha_2 \mathrm{e}^{\beta_2 q_{gi}} \tag{3.10}$$

In 2011 Rashid et al.[11] proposed an equation model, considering the variable decisions the flow, gas lift and the opening of the production choke, which is represented as a discreet variable.

$$q_{op} = c_1 + c_2\sqrt{q_{gi}} + c_3 q_{gi} \tag{3.11}$$

Some previous work used those equations as the main study to compare them and establish which one best fits and represents the GLPC. Equations by Alaracon et al.[13] and Rashid et al.[11] best fit in most of the cases for different operating conditions. This comparison was done using the least squares techniques, where the R^2 should approach 1 to become the best fitting equation. Therefore, those two equations were used for the optimisation of the gas lift system built in Excel, after finding the coefficient of the equation using the curve fitting tool in MATLAB (Chapter 4, Figure 4.2 and 4.3).

3.4.1.2 Piecewise-Linear Optimisation

Several kinds of linear programming problems use functions that are not really linear, but can be approximated by a series of linear segments that follow the gradient of the function. These "piecewise-linear" terms are easy to imagine, but can be hard to describe in conventional algebraic notation.

In this work a piecewise-linear optimisation of a non-linear function is computed in Excel using linear programming with binary integer variable y and z inside the Solver tool to find the maximum total oil production for a network system of five gas lifted wells.

In order to know and understand how the piecewise-linear programming works as a linear optimisation, some description are presented:

- An optimisation variable is added for each data point n in the gas lift performance curve (z_j in Figure 3.3).

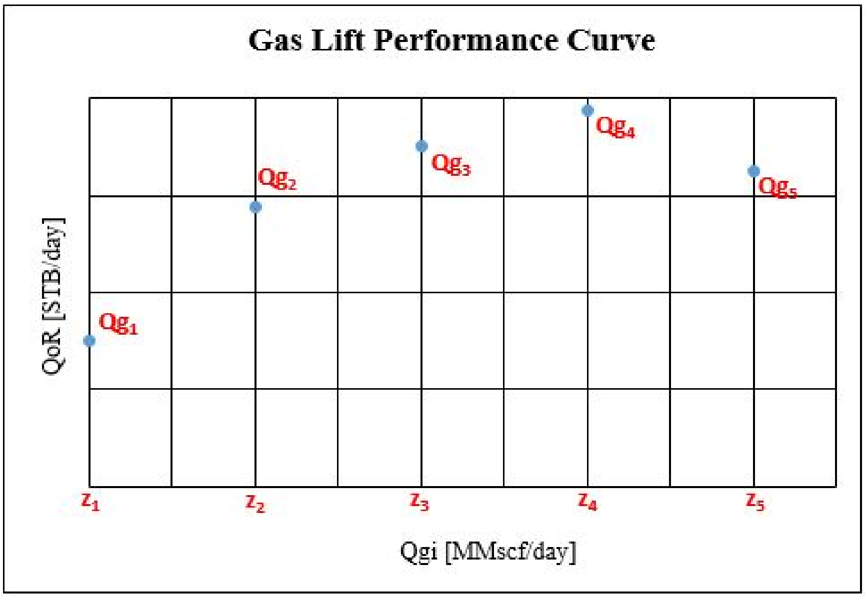


Figure 3.3: Data for the GLPC used in the piecewise-linear optimisation

The variable will be multiplied with the coordinates of each point, i.e. the gas injection rate and the oil produced. Afterwards a summation of the product between the coordinates of each point and the variable is calculated.

$$q_{opi} = \sum_{j=1}^{n} q_{oj} z_j \tag{3.12}$$

$$q_{gi} = \sum_{j=1}^{n} q_{gj} z_j \tag{3.13}$$

Where i= number of the well and j = number of data points in the GLPC

- The value of the variable z_i might vary between 0 and 1.
- To honour the adjacency condition, addition binary variables (y_j) have to be included. And only one of the adjacent variable is allowed to be different from zero.
- The sum of all variables has to be equal to 1 and will be added as additional constraints.
- The optimiser uses the Simplex method and Branch and Bound in Excel Tool.

3.4.2 Model-based Optimisation

The optimisation for a system using the model-based optimisation is done normally by using a computational software that takes into account the changes in the operation conditions during the production.

In this work three model schematic GAP software were used to allocate the amount of gas to be inject in each well in the system (described in Chapter 4 in section 4.3).

Chapter 4

Methodology

In this chapter the methodology used to achieve the aim of this thesis work are presented.

4.1 Gas Lift Performance Curve Elaboration

Gas lift performance curve is important during the optimisation in a systems using gas lift well. In this work some wells were modelled in PROSPER, which is a well performance, design and optimisation program which is part of the Integrated Production Modelling Tool kit (IPM). The step by step in appendices A shows how to design a gas lift well using PROSPER.

After modelling the well in PROSPER, the GLPC was generated (Figure 4.1) and the data points (gas injected and oil produced) were exported into Excel and then used in the optimisation using individual performance curve.

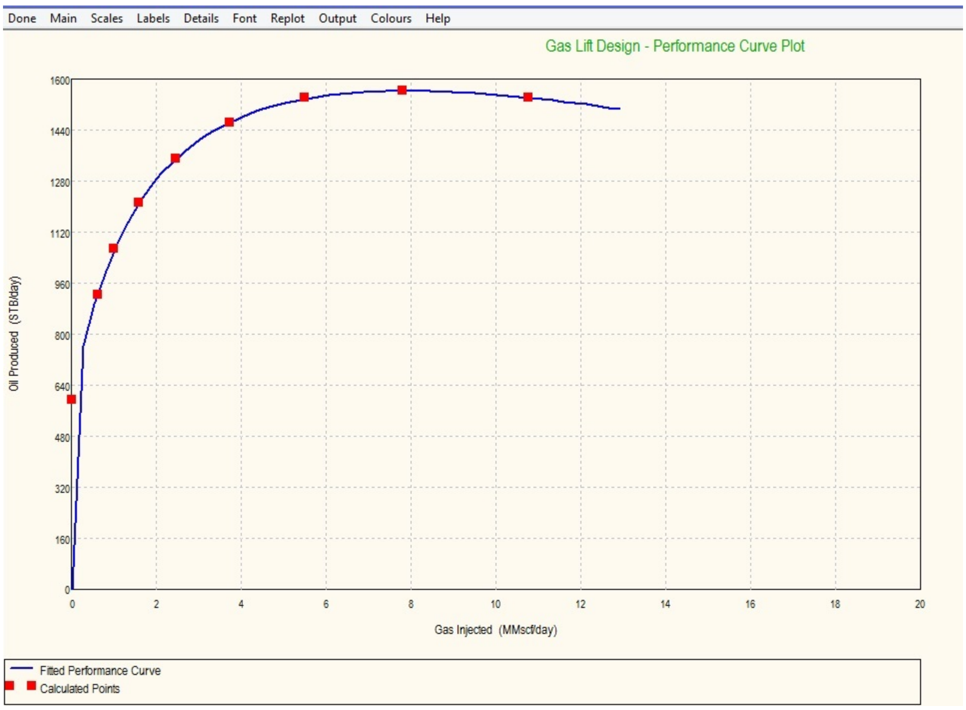


Figure 4.1: GLPC generated from PROSPER

4.2 Optimisation using Individual Gas Lift Performance Curve

In this optimisation method the data generated and exported from PROSPER were used. The simple system with five gas lift wells were modelled and the optimisation were performed using Solver Tool in Excel.

4.2.1 Curve Fitting Technique

As described in section 3.4, there are many equations that can be used to represent the behaviour of the lift performance curve. For this thesis work two equations were chosen, the choice was based on the previous studies, where the equation should best fit in the data presented. In the specific case the equation from Alarcón et al.[11] and Rashid et al.[13] were used.

In order to use the equation in the curve fitting technique, the coefficients should be found first. This can be found using different methods, example interation, here MATLAB curve fitting tool was used.

Figure 4.2 shows the MATLAB menu bar where the curve fitting application can be selected. In Figure 4.3 the coefficients of the equations and the R^2 are automatically calculated, after import the data and introduce the equation in the custom equation window.

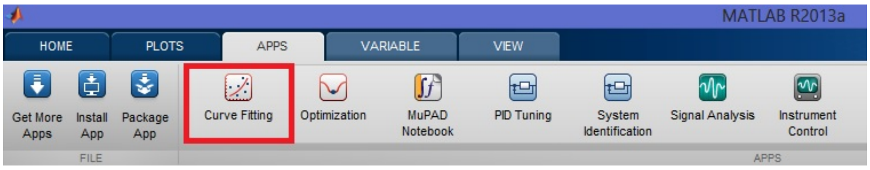


Figure 4.2: Matlab menu bar tool screen

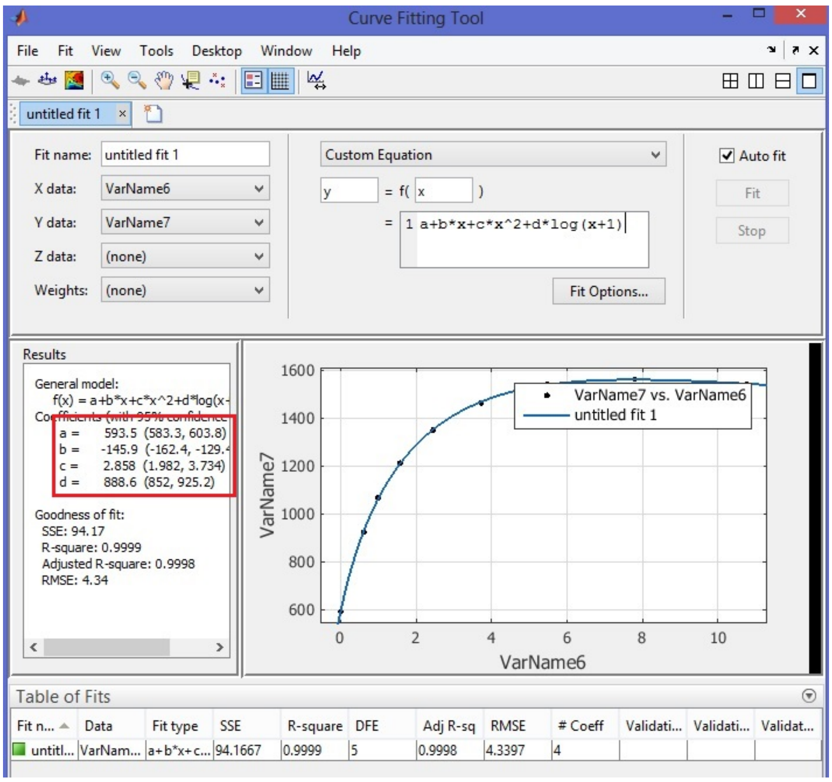


Figure 4.3: Matlab curve fitting tool

With the known equation coefficients, a simple excel sheet was built for the optimisation. For both equations a **Solver** Tool was used (Figure 4.4) where mathematical allocation algorithm problem for gas lift system were introduced with the set objective of maximising the total oil production, subjected to the constraints defined in the optimisation algorithm. For this optimisation technique a GRG non-linear method was selected.

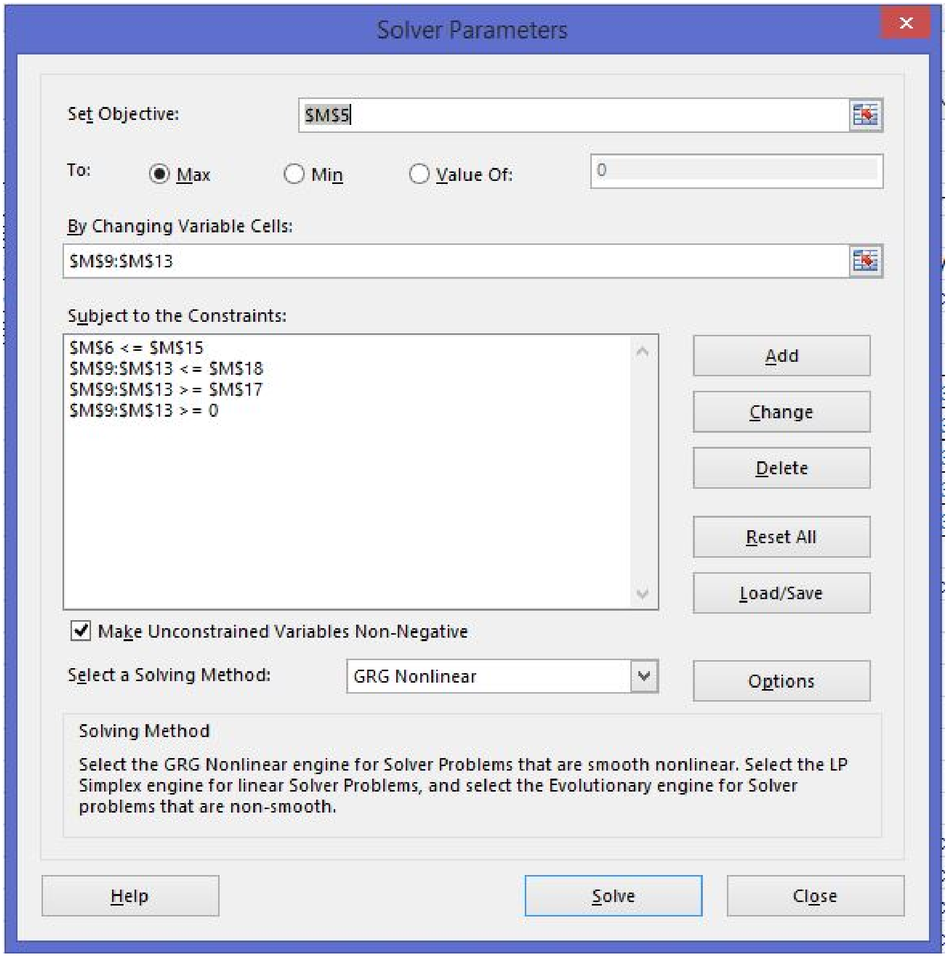


Figure 4.4: Excel Solver for curve fitting technique

4.2.2 Piecewise-Linear Optimisation

The optimisation using the piecewise-linear programming was performed after the data is generated in PROSPER. Like in the previous process a simple excel sheet was built and **Solver** tool used for the optimisation (Figure 4.5).

Different from the curve fitting technique the non-linear function was subjected to the constraints represented in the mathematical algorithm for gas lift system and the piecewise-linear programming. The optimisation technique selected in Solver was Simplex.

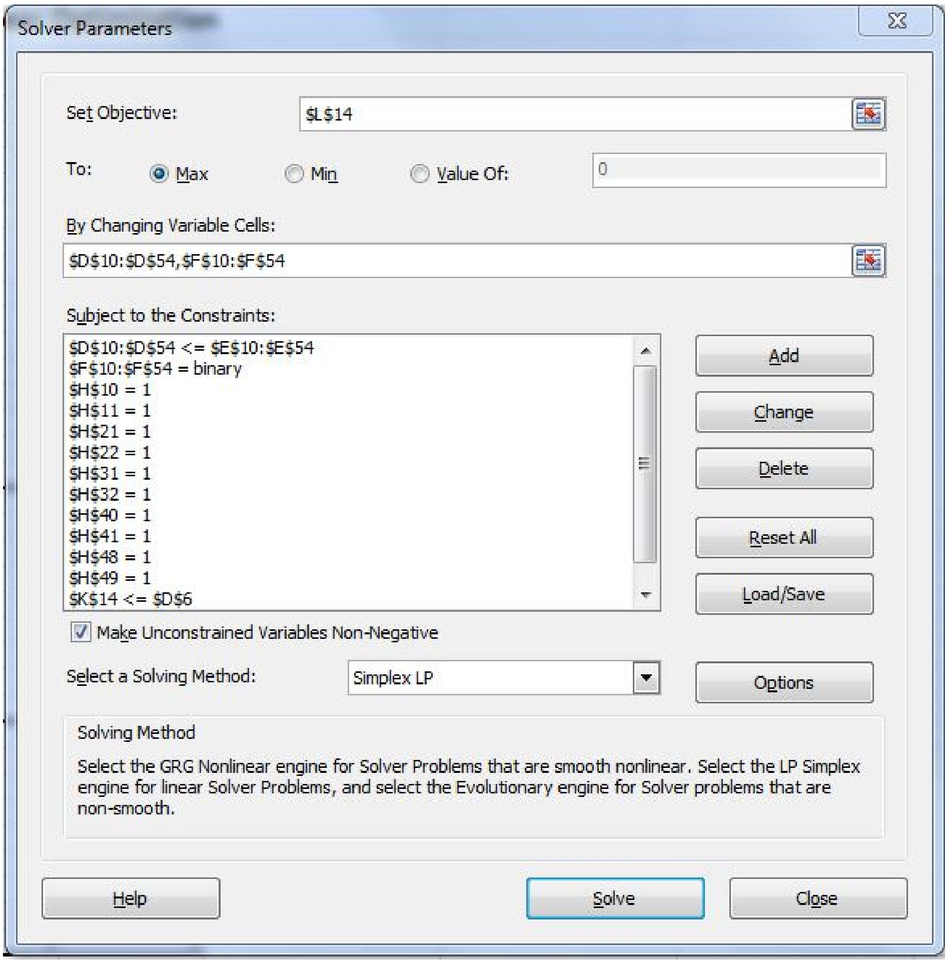


Figure 4.5: Excel Solver for piecewise-linear programming method

4.3 Model-Based Optimisation using GAP

Petroleum Experts General Allocation Package (GAP) is a multiphase flow simulator that is able to model and optimise production and injection networks. There are several optimisation techniques available in the literature, some are simple as simplex (linear programming) and equal slope, while other are more complex like sequential quadratic programming (SQP). In GAP the method used is the SQP.[1]

In this work, optimisation using GAP was performed to determine the optimum amount of gas to be injected in each well that yields the maximum oil production. The step by step optimisation using GAP is described in appendices C. For the optimisation using GAP three integrated model schematic were created.

Figure 4.6 shows the first model system with five gas lifted wells producing to a common junction and the separator that is located near the wells.

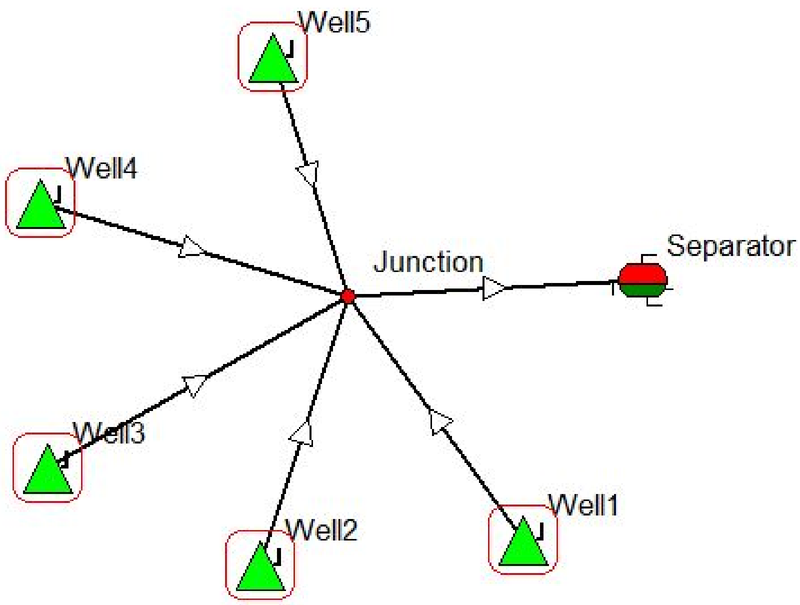


Figure 4.6: Gas lift network design in GAP - integrated model schematic 1

Figure 4.7 shows the second model system with five gas lifted wells producing to a common junction, then a long pipeline with a length of 12km and the separator.

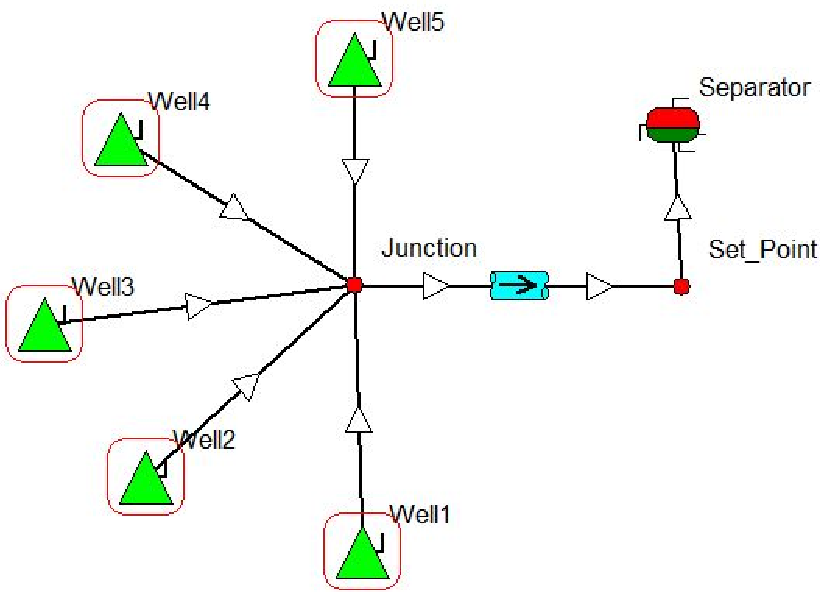


Figure 4.7: Gas lift network design in GAP - integrated model schematic 2

Figure 4.8 shows the last model system with five gas lifted wells, each well producing to its own junction, then a pipe (1km) and then a junction where all pipes are commingled, then a long pipeline (4km) and a separator.

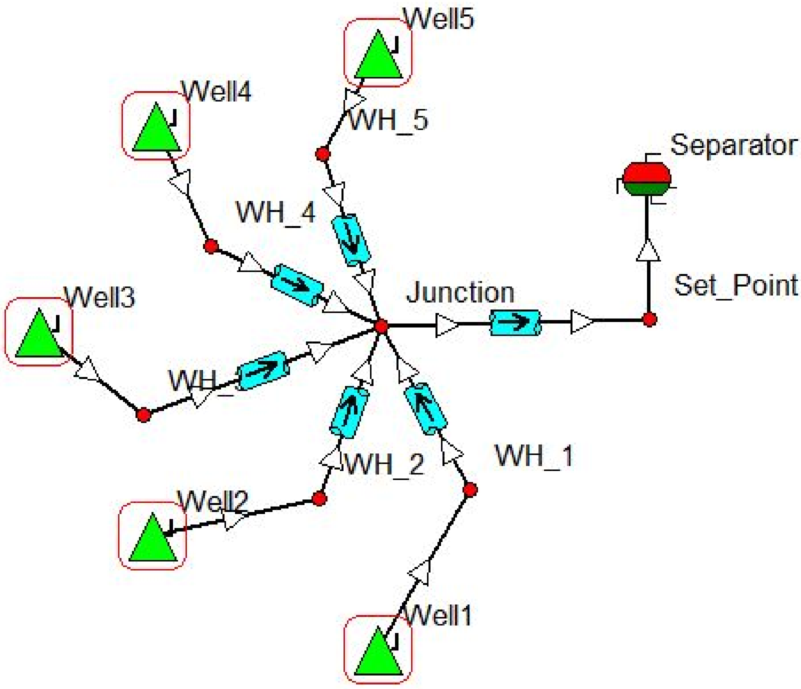


Figure 4.8: Gas lift network design in GAP - integrated model schematic 3

4.4 Comparison of the Total Oil Production

After performing the optimisation for the production system containing five gas lifted wells using the individual GLPC and the model-based optimisation in GAP, there is an interest of knowing if the optimum oil production calculated in each method are close to each other.

To make this comparison, calculations using Equation (4.1) were performed. The equation represents the deviation between the total oil production in the system and the amount of injected gas per well found by using a model-based optimisation GAP and the individual well performance curve optimisation. This deviation was represented as absolute percentage of error for the values of total oil production.

$$\%Error = \left|\left(\frac{Method\,2 - Method\,1}{Method\,2}\right)\right| \times 100 \tag{4.1}$$

Where
Method 1 = optimisation using individual well performance
Method 2 = model-based optimisation in GAP

If the deviation value in both case of total oil production and injected gas per well is more than 100% it indicates that the optimum point found by method 2 is completely different by the optimum found in method 1.

Chapter 5

Simulation Results and Discussions

In this chapter the simulation results for the cases studies are presented and discussed. This includes the GLPC generated, the mathematical optimisation for a group of gas lifted wells using individual GLPC and GAP Software optimisation. Comparison of the total oil production and the injected gas per well found for those methods were done to see if they are close from each other. Comparison also aimed to see if it is possible to perform the optimisation using method 1 as a start point to the method 2 or even to use for a practical propose when performing a method 2 is expensive. The method 1 assumes that there is no change in the operation conditions for a particular well due to the effect of neighbour wells and in method 2 this assumption is not valid.

The wells were modelled in PROSPER and the GLPC data were generated and exported, then used in optimisation using method 1. For GAP optimisation the well modelled is used as input file.

5.1 Case 1: Five Wells with Same Layout

In this case a system of wells was created using the same layout design in PROSPER, i.e., same PVT and IPR properties, well completion and gas lift well design. Using the same system, different reservoir pressure were tested to see the effect in the GLPC and in the optimisation process.

For this case two different layout wells with different properties (Table 5.1) were studied, to see if the observation in one well will be the same for different well properties.

Table 5.1: Well data for the well and flowline system

Parameter	**Unit**	**Layout 1**	**Layout 2**
Reservoir Pressure	psig	3026	3700
Oil gravity	^{o}API	39	37
Gas specific gravity		0.798	0.76
PI	STB/D/psi	5	5
Water salinity	ppm	100000	23000
GOR	scf/STB	500	800
Bottom hole temperature	^{o}F	250	210
Well head pressure	psig	200	250
Well depth	ft	8000	9000
Tubing ID	in	4.05	4.05
Operation valve depth	ft	7800	8000
Injection gas gravity		0.7	0.7
Water cut	%	15	40

5.1.1 Systems with Well Layout 1

Before the optimisation using different methods, it is necessary to have a look at the GLPC to see how the well will behave in different operation conditions.

Figure 5.1 present the GLPC for layout well 1. It is observed that for any changes in reservoir pressure the GLPC also changes for the well designed and for all the GLPC there is no need of an initial volume of gas injection to produce oil.

When the reservoir pressure increases the oil produced also increases, due to the wellhead pressure that doesn't change during the gas lift design. Then with the same wellhead pressure once the reservoir pressure changes the GLPC will also change.

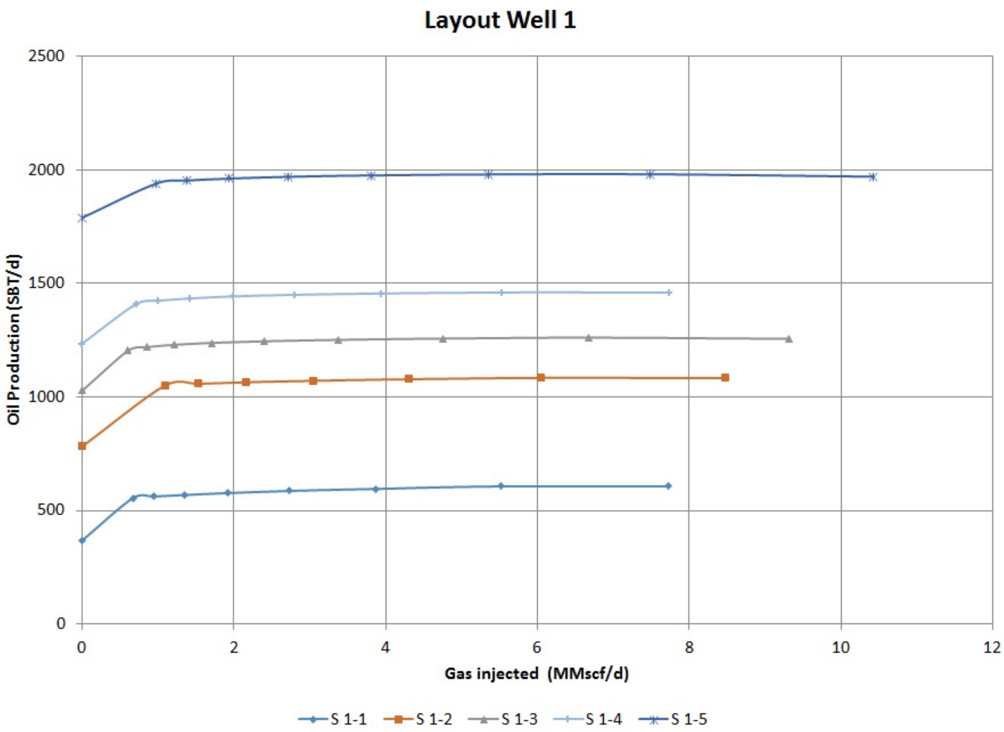


Figure 5.1: GLPC for different reservoir pressures layout 1

The GLPC is generated automatically in PROSPER, it depends on many factors as water cut, wellhead pressure, GOR and other data supplied in the gas lift design screen and PVT data (Appendices A, Figure A.2 and A.18).

Table D.1 shows that the oil production in layout 1 for different reservoir pressure do not reach more than 2000 STB/D, and the gas injection to reach the maximum oil production is less than 10 scf/D.

5.1.1.1 Total Oil Production Optimisation

After creating the individual wells GLPC (Table D.1), ideal systems with five gas lifted wells were create and optimised using method 1. During the optimisation each GLPC was representing a system, this means that for a particular system data from well 1 = well 2 = well 3 = well 4 = well 5. The optimum oil production found using different techniques are presented in Table D.12 to D.16 in appendices D for a wells with layout 1. Then the values were used to compute the deviation between the methods and represented into graph.

Figure 5.2 to Figure 5.4 represents the deviation between the total oil production calculated using GAP-1, GAP-2 and GAP-3 with the piecewise-linear optimisation technique respectively. The figures shows that when the reservoir pressure increased the deviation between the values also increased.

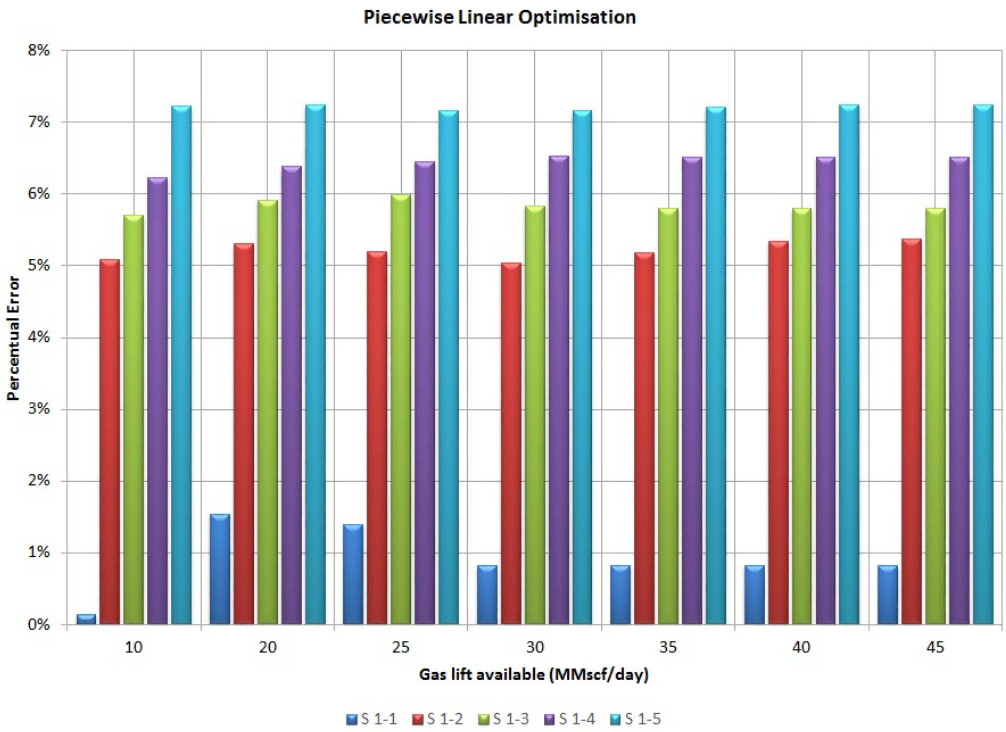


Figure 5.2: Deviation between GAP-1 and Piecewise method for different systems layout1

For the case in Figure 5.3 and 5.4 the deviation value for the systems is less than the deviation found when the model GAP-1 is compared.

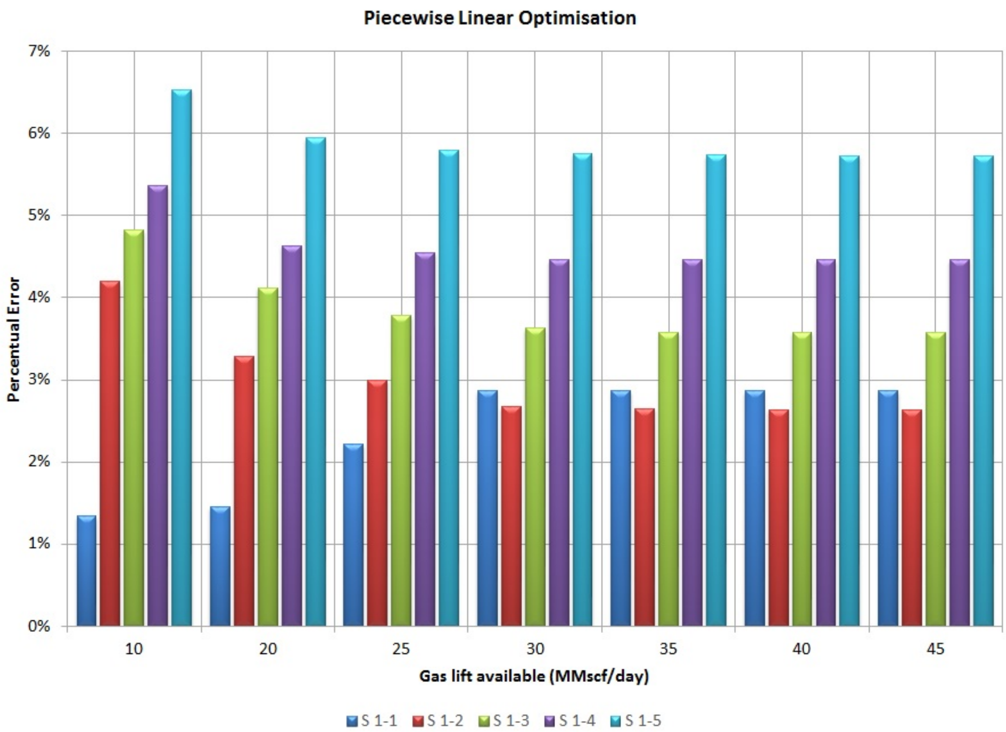


Figure 5.3: Deviation between GAP-2 and Piecewise method for different systems layout 1

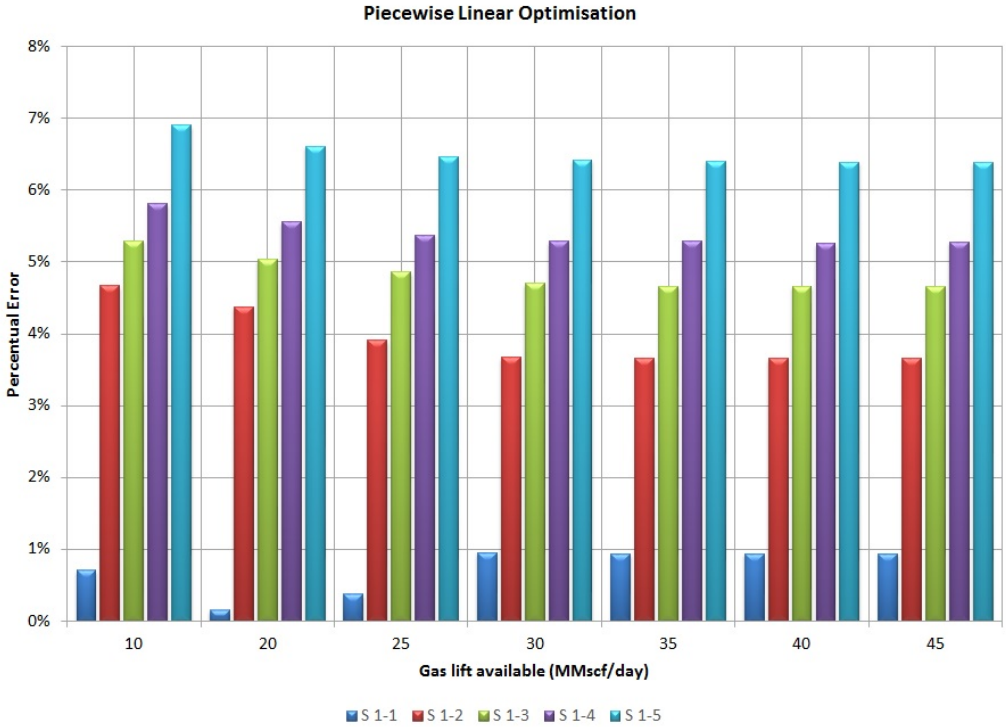


Figure 5.4: Deviation between GAP-3 and Piecewise method for different systems layout 1

Figure 5.5 to Figure 5.7 represents the deviation between the total oil production calculated using GAP-1, GAP-2 and GAP-3 with the curve fitting technique (using Alaracón equation) respectively. The deviation has the same behaviour as seen in piecewise technique.

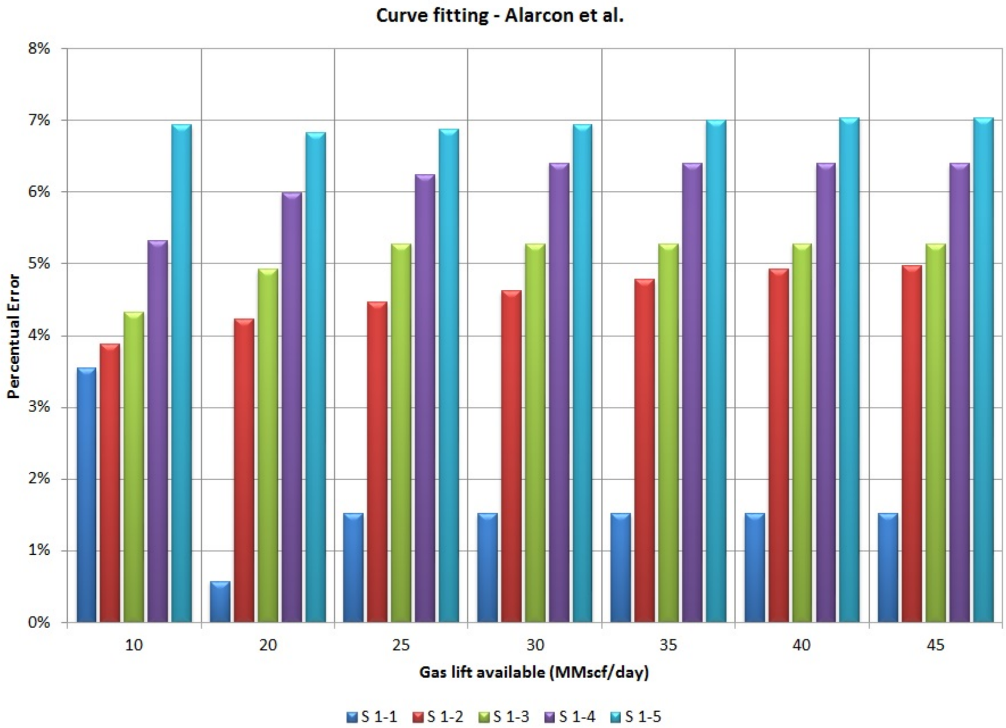


Figure 5.5: Deviation between GAP-1 and curve fitting method using Alarcón equation for different systems layout 1

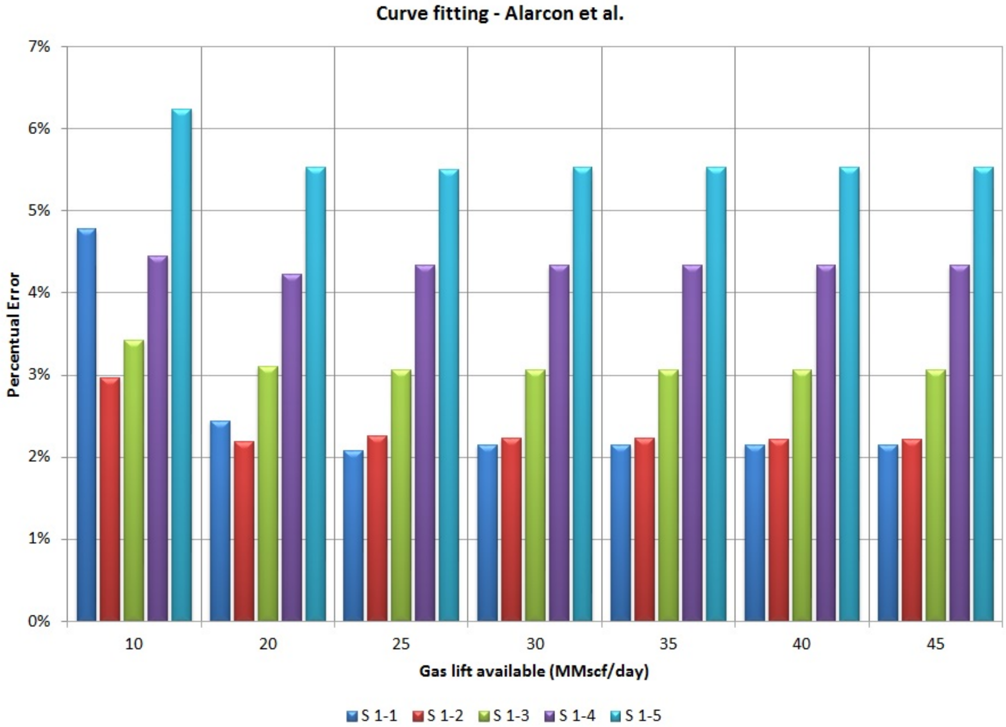


Figure 5.6: Deviation between GAP-2 and curve fitting method using Alarcón equation for different systems layout 1

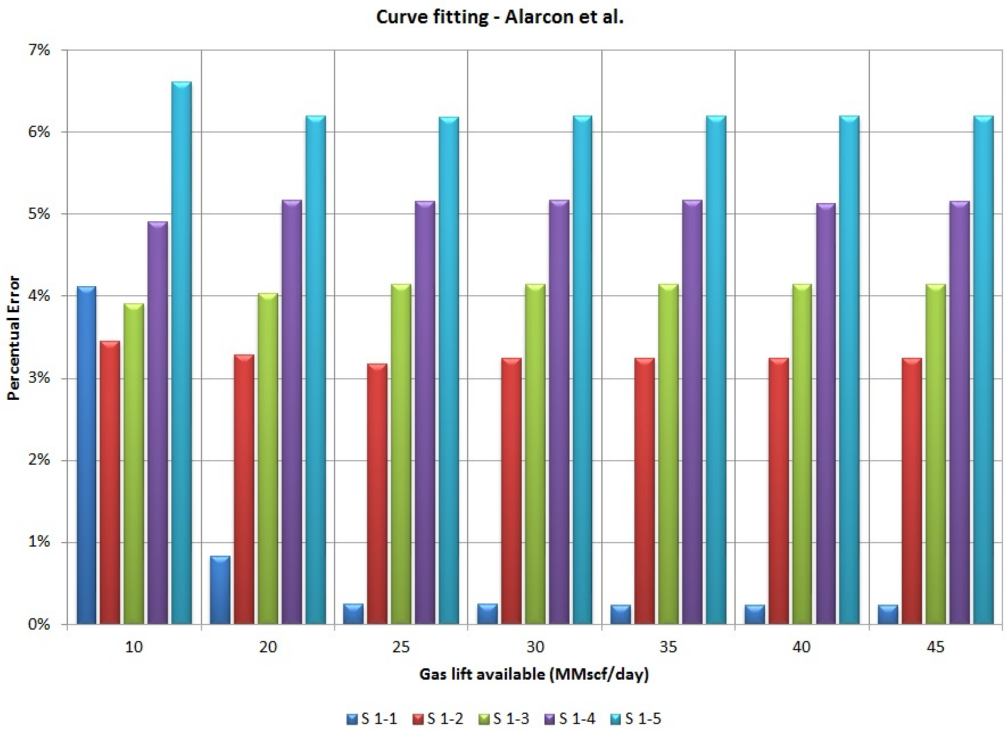


Figure 5.7: Deviation between GAP-3 and curve fitting method using Alarcón equation for different systems layout 1

Figure 5.8 to Figure 5.10 represents the deviation between the total oil production calculated using GAP-1, GAP-2 and GAP-3 with the curve fitting technique (using Rashid equation) respectively.

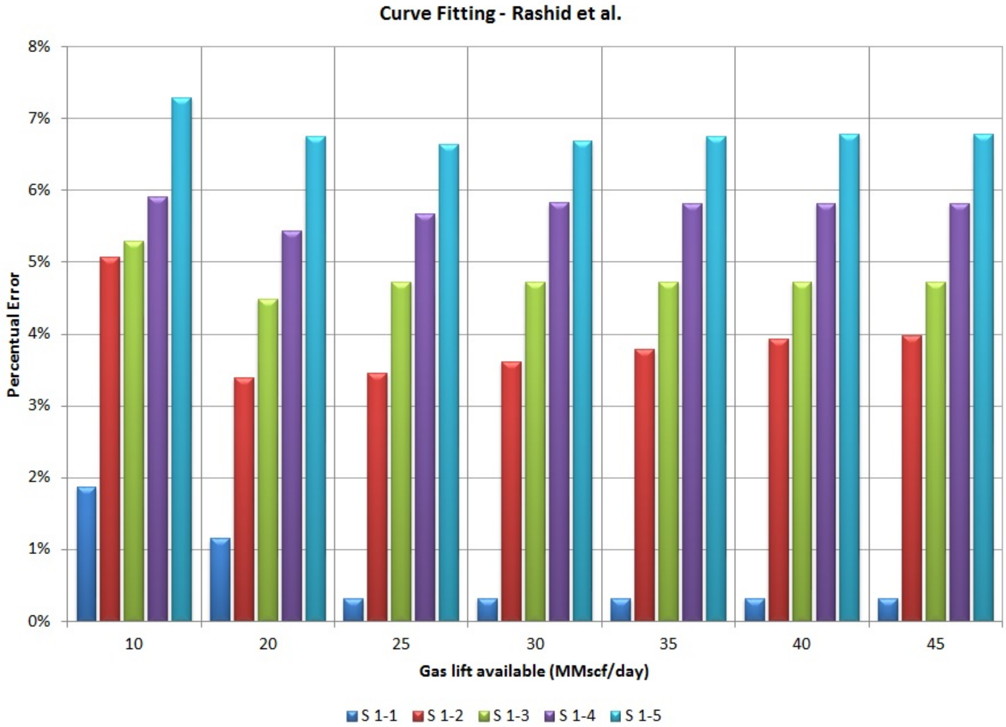


Figure 5.8: Difference error between GAP-1 and curve fitting method using Rashid equation for different systems layout 1

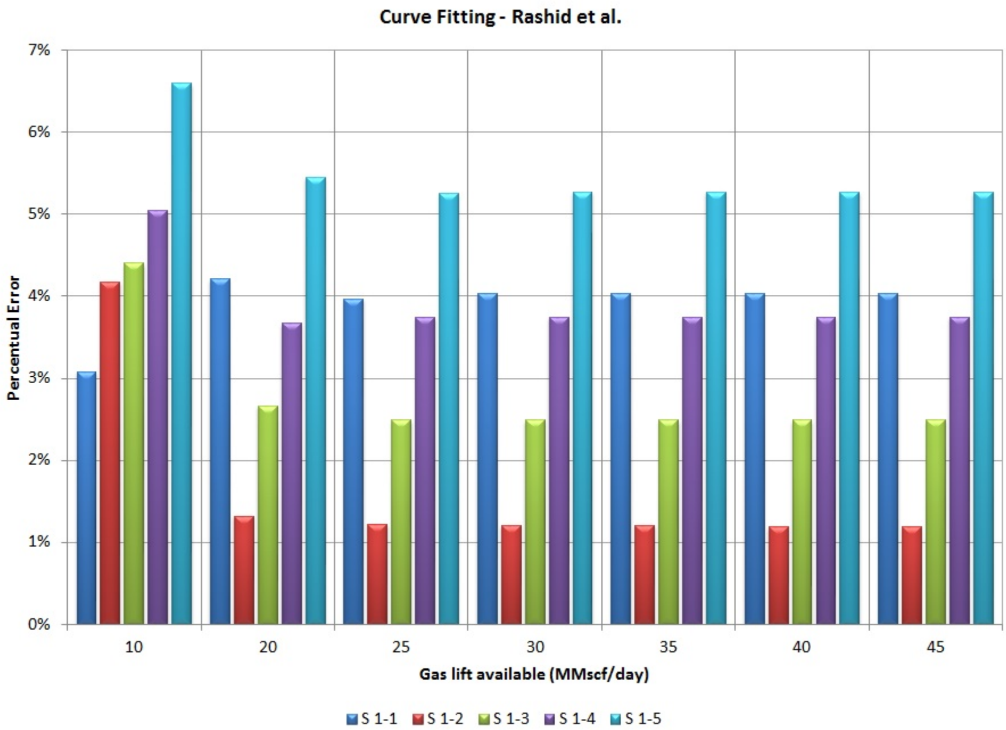


Figure 5.9: Difference error between GAP-2 and curve fitting method using Rashid equation for different systems layout 1

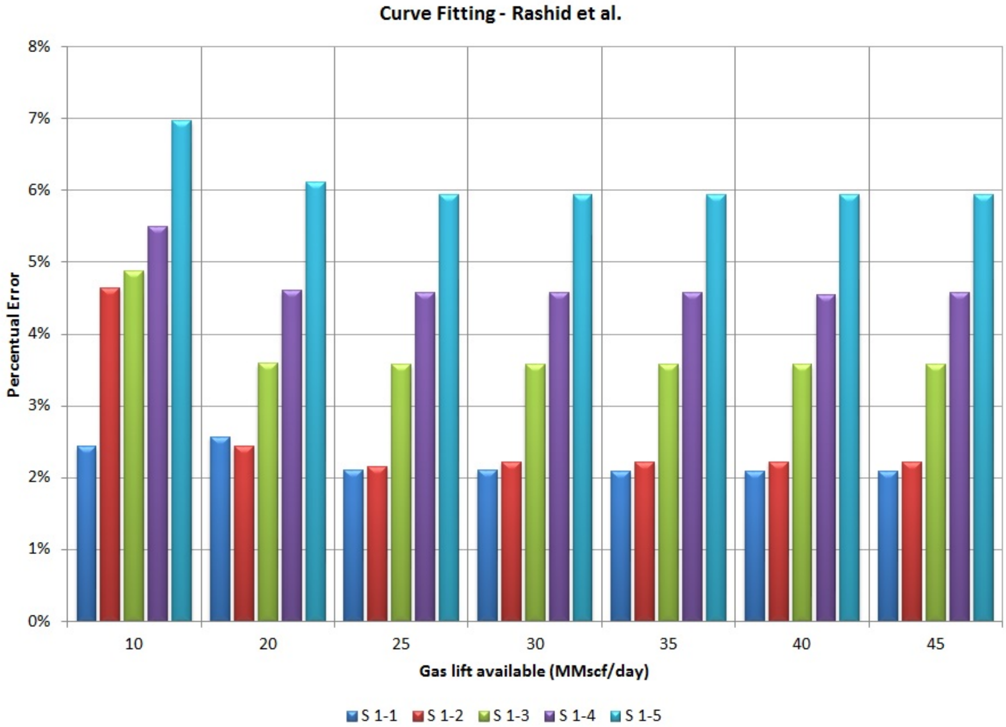


Figure 5.10: Difference error between GAP-2 and curve fitting method using Rashid equation for different systems layout 1

Comparing the graphs it is possible to observe that the trend are not equal when using different techniques in the individual GLPC optimisation methods. The deviation calculated between the different model schematic in GAP and the curve fitting technique using Rashid et. al. equation is less comparing with other techniques in general(Table D.27 to D.29).

The total number of iteration and total time used in curve fitting technique using Rashid et al. equation is less comparing with other methods.

In the model GAP-2 the deviation calculated using curve fitting technique is almost the same for both equation. The total oil production is small comparing with the model GAP-1 and GAP-3 (Table D.12 to Table D.16), this can be cause by the long distance of the pipeline from the junction to the separator.

5.1.2 Systems with Well Layout 2

Figure 5.11 represent the GLPC for the case of layout well 2. For the present layout the performance curve behaves in the same way as layout well 1, where the GLPC have different response for different reservoir pressure. The oil production also increases with the increases in reservoir pressure.

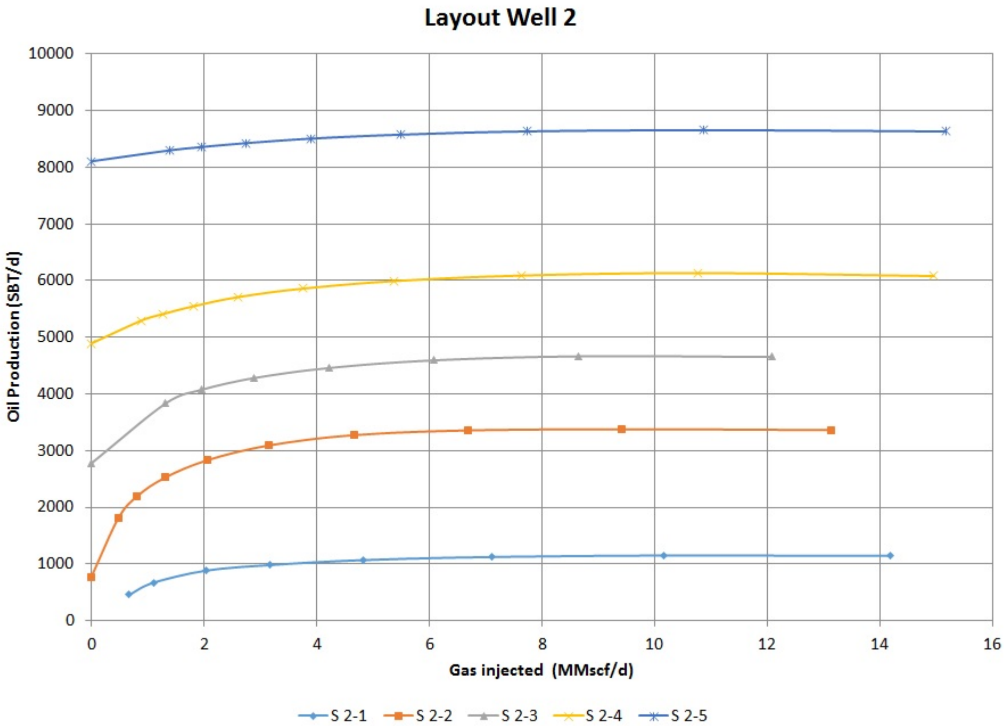


Figure 5.11: GLPC for different reservoir pressures layout 2

For this layout the initial amount of gas lift is required when the well have low reservoir pressure in order to produce oil.

Table D.3 shows that the oil production is very high more than 2000 STB/D when the reservoir pressure increases. In comparison with layout 1 the produced oil does not increase to much with increase in reservoir pressure. The gas injection need to reach the maximum oil production is more than 10 scf/D for all the reservoir pressure.

Generally, the difference in oil production and gas injected in the well is due to the different parameters introduced during the well design, that makes the GLPC data different for a particular case.

5.1.2.1 Total Oil Production Optimisation

For layout 2 the same studies was done to see if the observation in layout 1 can be seen for different systems. Figures 5.12 to 5.18 shows that for a different well design the observations are not the same as in layout 1, because when the reservoir pressure increase the deviation decreases. Figure 5.12 to Figure 5.14 represents the deviation between the total oil production calculated using GAP-1, GAP-2 and GAP-3 with the piecewise-linear optimisation technique respectively.

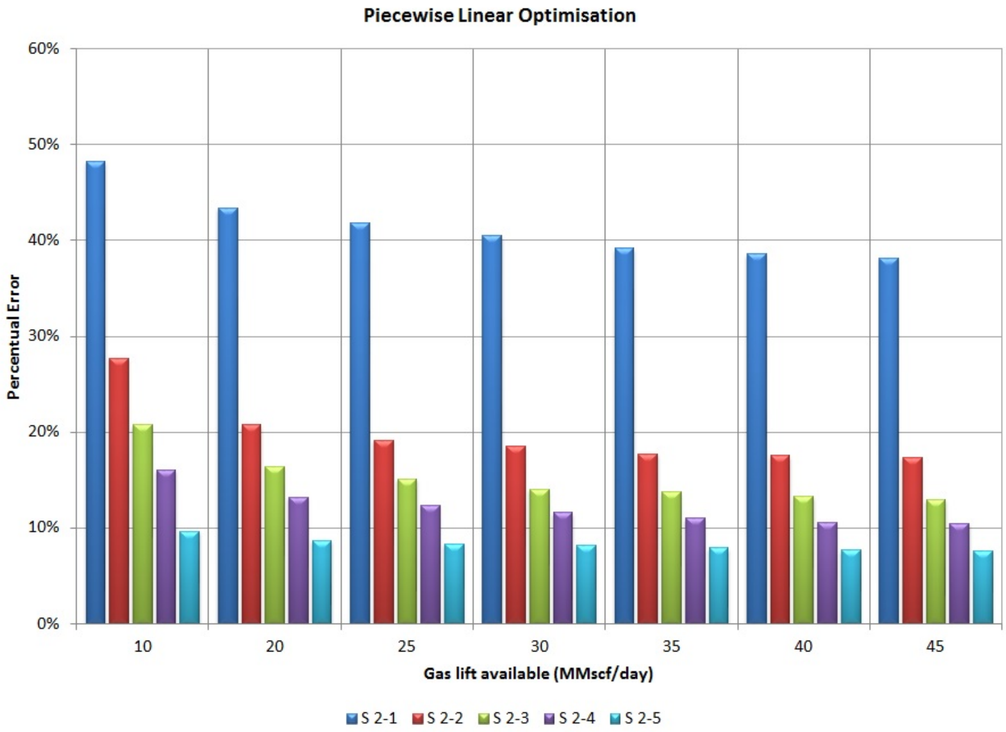


Figure 5.12: Deviation between GAP-1 and piecewise method for different layout2

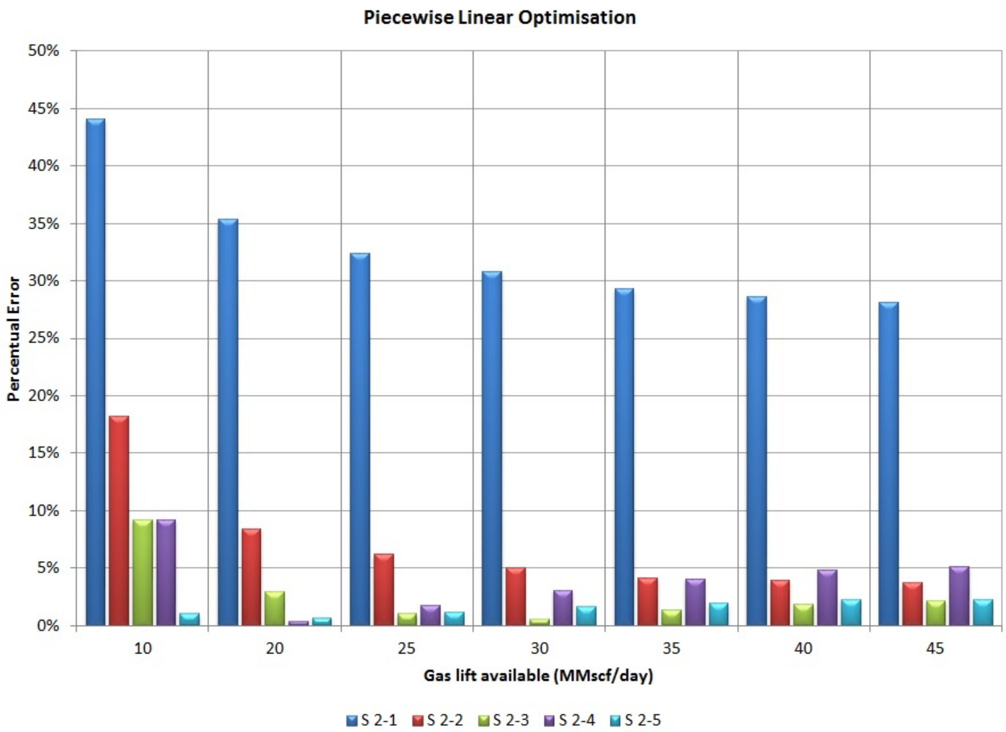


Figure 5.13: Deviation between GAP-2 and piecewise method for different layout2

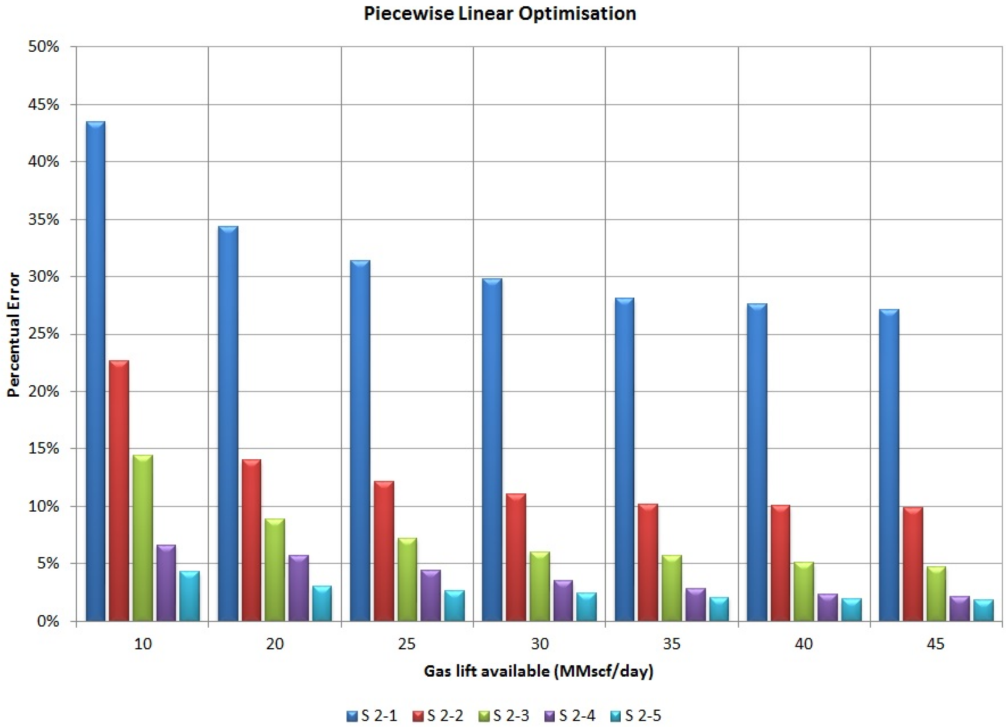


Figure 5.14: Deviation between GAP-3 and piecewise method for different systems layout 2

Figure 5.15 to Figure 5.17 represents the deviation between the total oil production calculated using GAP-1, GAP-2 and GAP-3 with the curve fitting technique (using Alaracón equation) respectively.

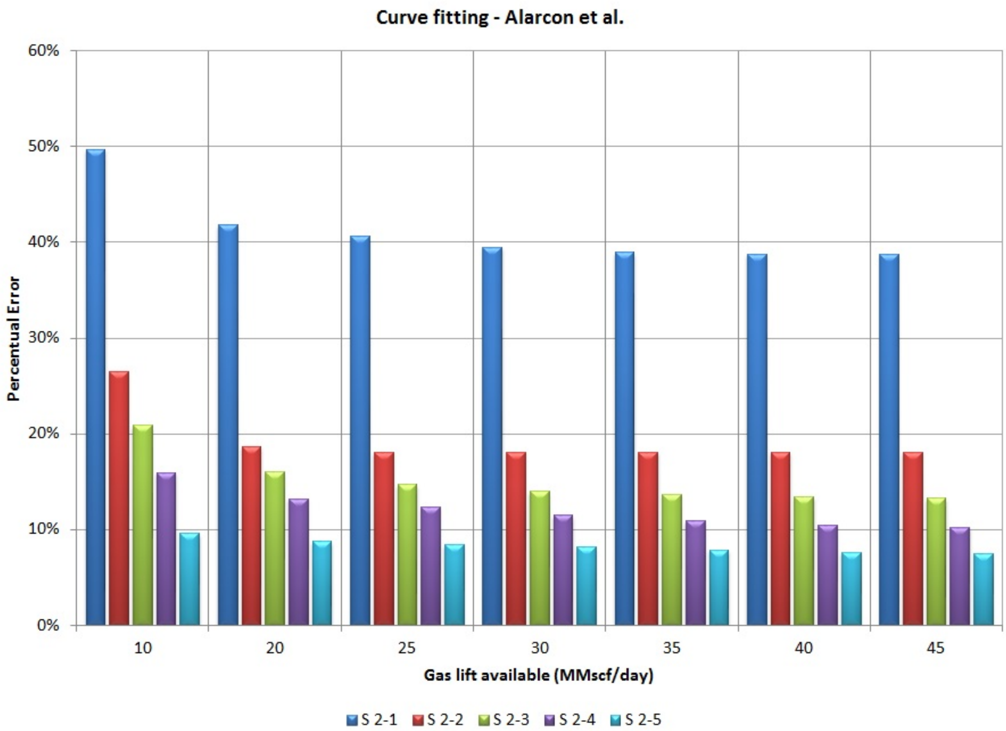


Figure 5.15: Deviation between GAP-1 and curve fitting method using Alarcón equation for different systems layout 2

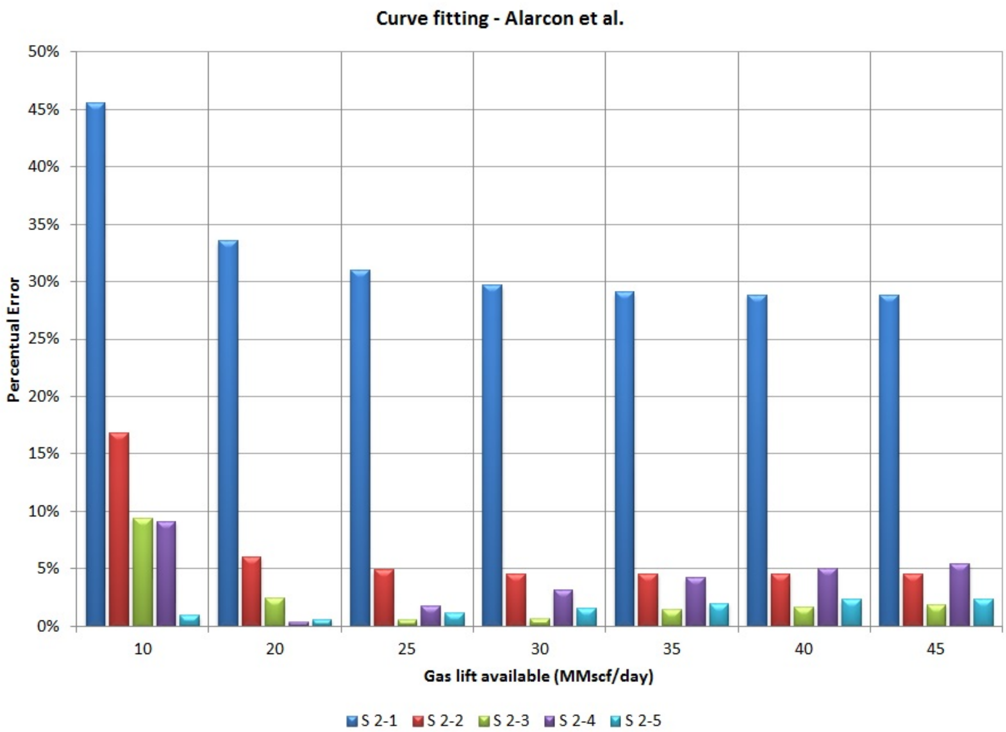


Figure 5.16: Deviation between GAP-2 and curve fitting method using Alarcón equation for different systems layout 2

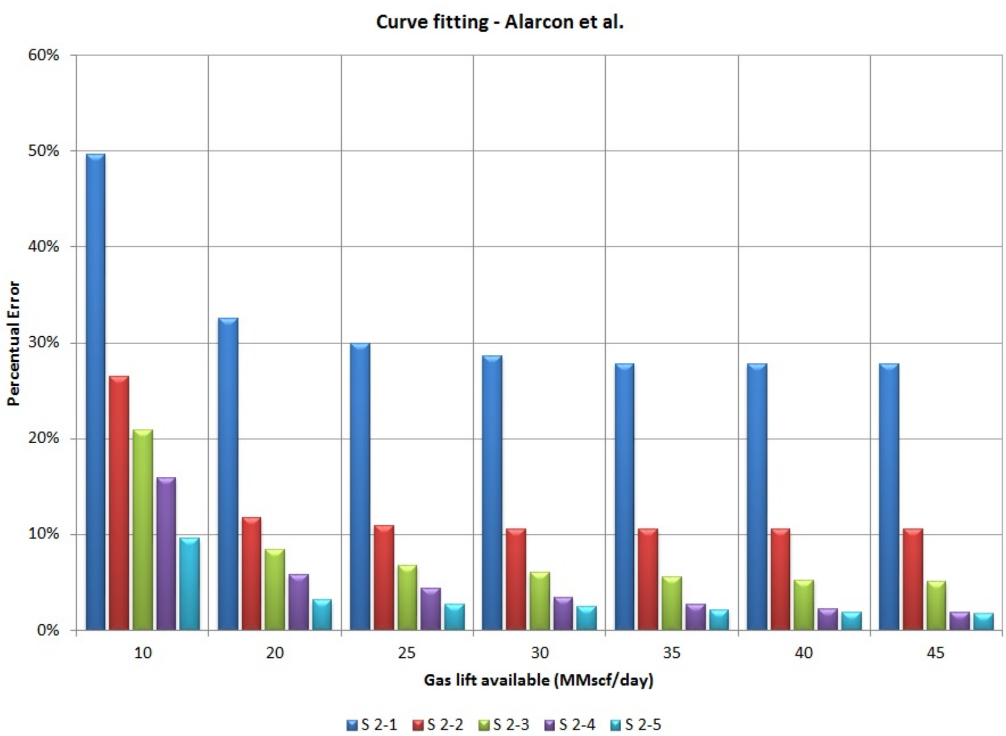


Figure 5.17: Deviation between GAP-3 and curve fitting method using Alarcón equation for different systems layout 2

Figure 5.18 to Figure 5.20 represents the deviation between the total oil production calculated using GAP-1, GAP-2 and GAP-3 with the curve fitting technique (using Rashid equation) respectively.

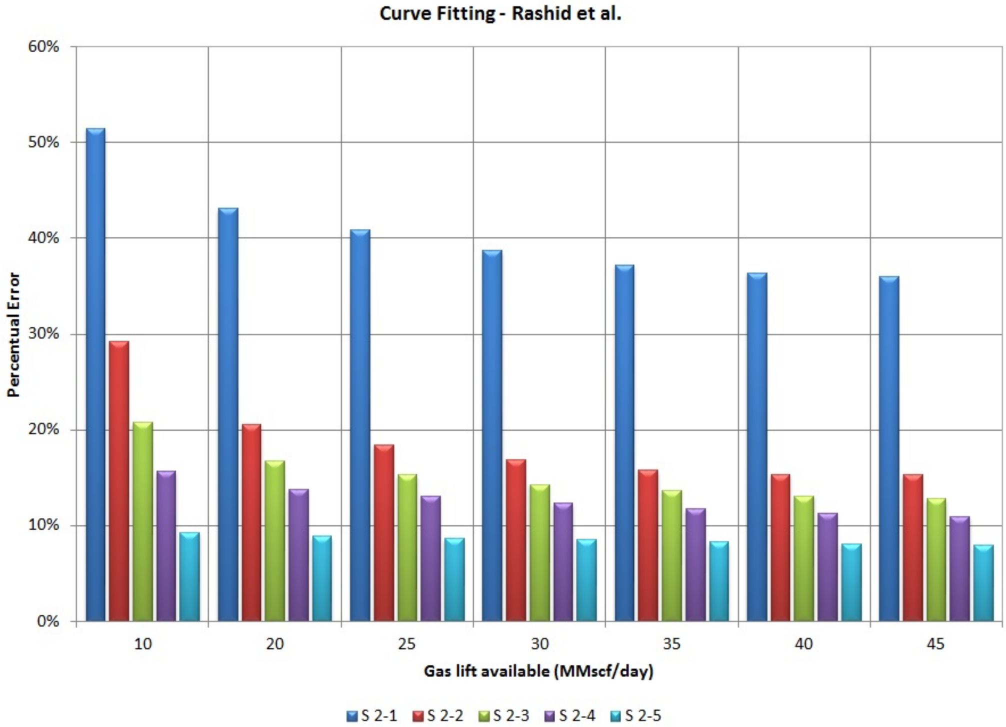


Figure 5.18: Deviation between GAP-1 and curve fitting method using Rashid equation for different systems layout 2

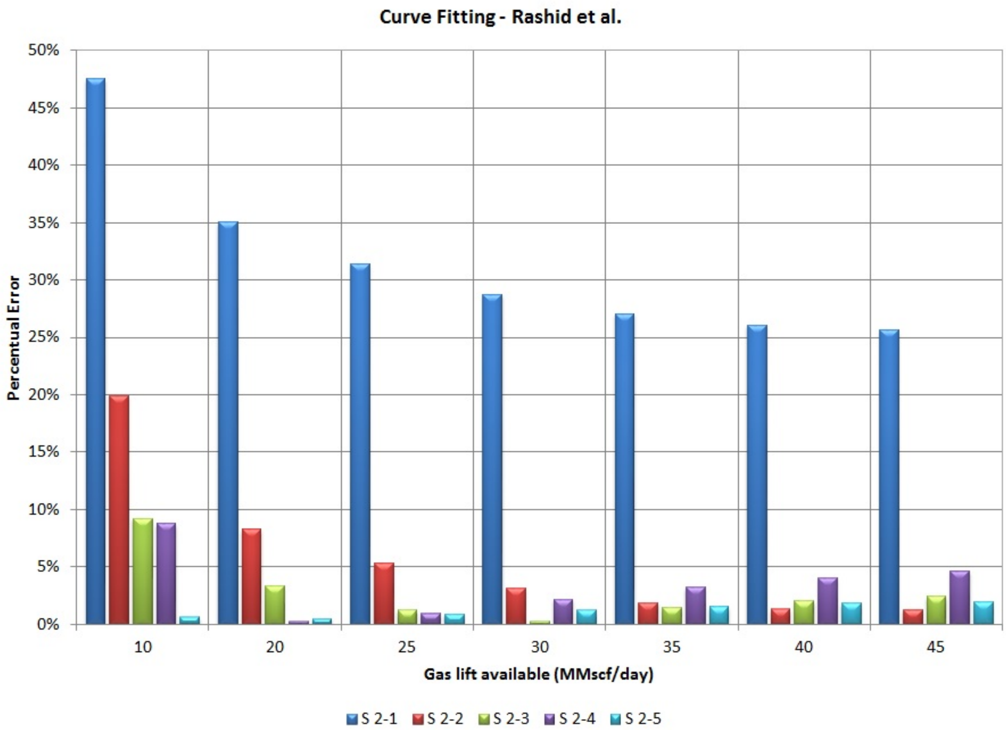


Figure 5.19: Deviation between GAP-2 and curve fitting method using Rashid equation for different systems layout 2

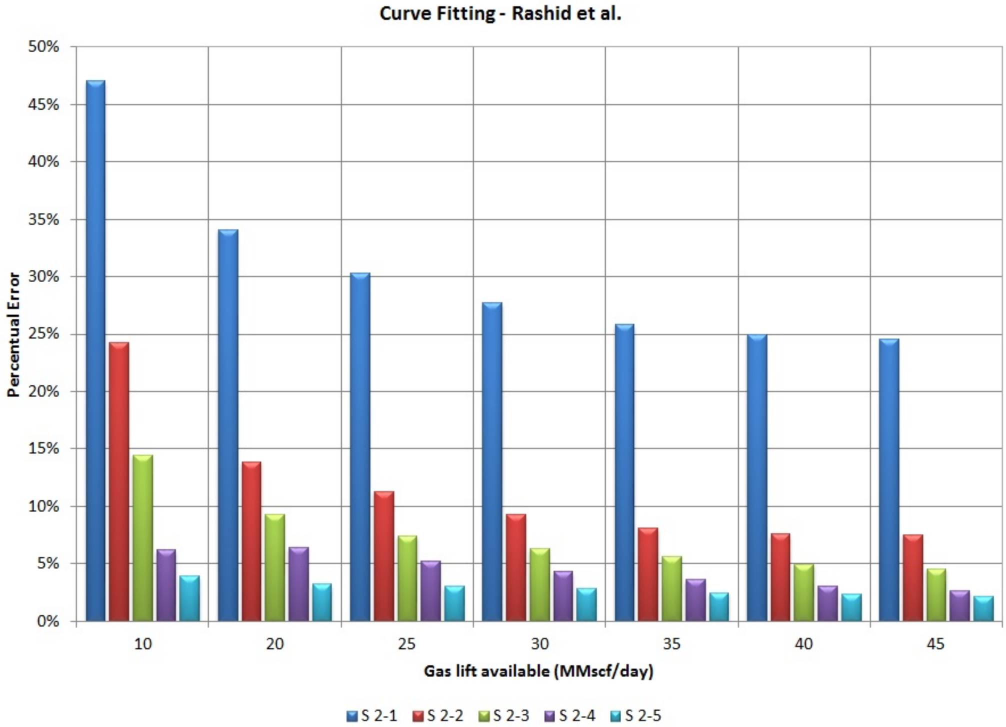


Figure 5.20: Deviation between GAP-3 and curve fitting method using Rashid equation for different systems layout 2

Comparing the graphs it is possible to observe that the trend are not equal when using different techniques in the individual GLPC optimisation methods, the same happened for layout 1. The deviation calculated between the different model schematic in GAP and the piecewise-linear optimisation is high comparing with other techniques in general (Table D.30 to D.32).

The total number of iteration and total time used in piecewise-linear optimisation is greater than other methods.

During deviation calculation for layout 2, it was observed that for lower reservoir pressure the deviation tends to be very high (more than 20%) in comparison with all the GAP model schematic. Therefore, some analyses were done with the values in appendices D to identify why this happen.

Table D.3 shows that, for the system 2-1; Pr = 2000psig an initial gas injection rate is needed so that the well can produce. In Table D.4 system 2-1, the ALaracón and Rashid equation first coefficient value are different from each other, this is not observed for all the systems created with this layout.

5.1.3 System with Well Layout 3

The following system was created to see if the deviation value is affected when the first coefficient value for the equation used in the curve fitting technique are different.

In Table D.5 data of the GLPC generated in PROSPER are presented where the initial gas injected is greater than zero (0.26 scf/D). This data were used in all the optimisation methods. During the optimisation in Excel for the case of curve fitting technique the coefficient of the equations used were calculated as shows in Table 5.2. Where is possible to see that the value of C_1 is different in both equation and this may affect optimum oil production found in this system.

Table 5.2: Equation coefficient

Equation	C1	C2	C3	C4
Alaracón	138	-299	9.239	1339
Rashid	-106.6	1066	-196	

If the above case is compared with the system 2-1 (Table D.33) when the reservoir pressure is 2000 psig in layout 2, the deviation is 58.94% and other 40.56% using Rashid equation in the curve fitting technique. This difference is due to the different in the oil production rate, the well starting with gas injection rate equal to 0.26 scf/D have high oil production rate comparing with the well starting with 0.67 scf/D. In system 2-1 oil production doesn't increase to much with the gas injection, comparing with the case above where the oil production increases almost 950STB/D with the gas injection.

Generally, if two systems with well having the initial gas injection greater than zero, the deviation will be high for the well with high oil production.

5.2 Case 2: Five wells with Different Layout

In this section four different scenarios were create, where each of them contain a network system of five gas lifted wells different form each other, i.e., the wells have different PVT and IPR properties, wells completion and gas lift well design.

5.2.1 System 1

In Figure 5.21 it is possible to see that each well have difference response in the GLPC, where two wells have high oil production comparing with other and the wells are producing without an initial volume of gas injection.

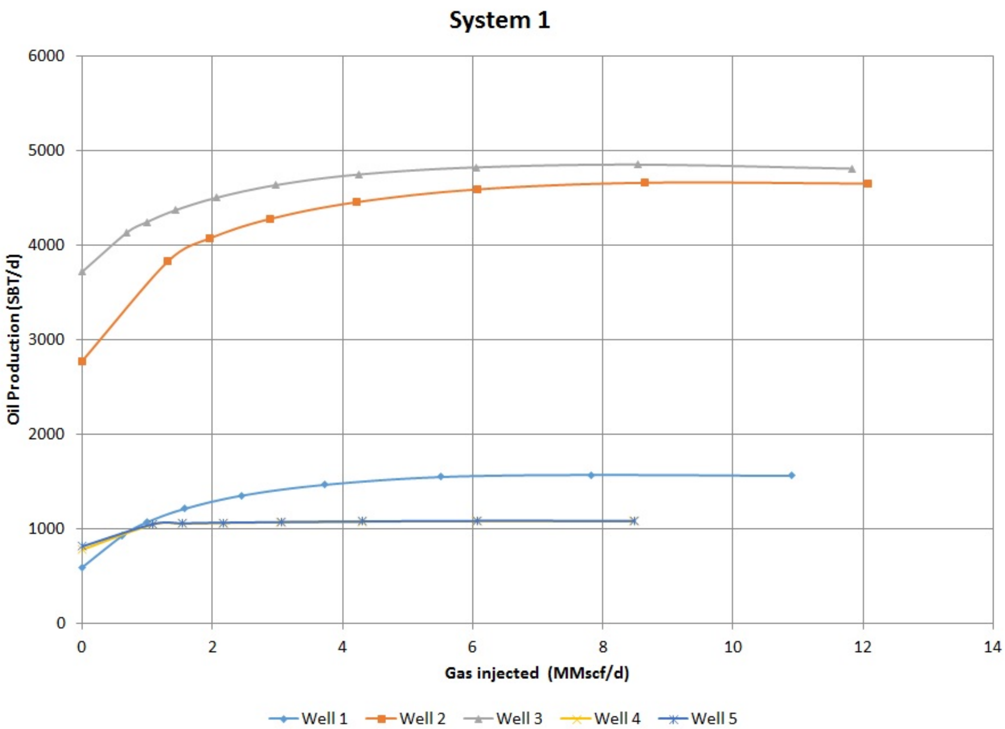


Figure 5.21: GLPC for system 1

Form the table D.7 the coefficients for the equation used, doesn't differ to much form each other, but there are not the same because the gas injection and the oil production for some of the wells are high. For well 4 and 5 when the gas injection rate is lower the coefficient are almost the same.

Table D.34 shows that in case for comparison with the GAP-1 the deviation is around 9%. For GAP-2 the deviation value is very low because the optimum found in method 1 is almost the same as method 2. For the case of gas injected per well the deviation is high comparing with the deviation calculated between method 1 and the GAP-1 and GAP-3.

5.2.2 System 2

Figure 5.22 represent the GLPC for the system 2. The wells are producing at gas injection rate greater than 10 scf/D and the oil production rate is lower less than 2000 STB/D.

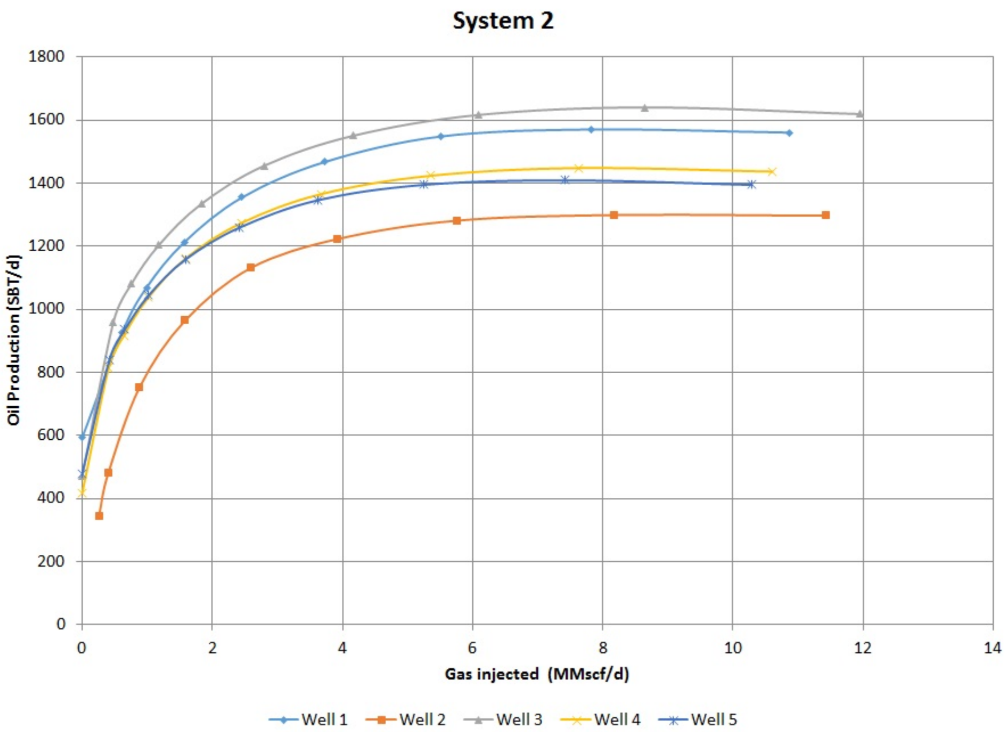


Figure 5.22: GLPC for system 2

Table D.8 shows the data used in the optimisation calculation, it's possible to see that for well 1 and well 2 the gas injected at the beginning of GLPC is greater than zero. This may affect the total oil production of the system calculated using the method 1.

Table D.9 shows that the first coefficient for the equations used are different for each other in all the well. Note that in well 2 the difference between the coefficient are high comparing with another well and this is the well that need the initial gas injection rate greater than zero. The deviation between the method 1 and all GAP model schematic is higher than 10%.

5.2.3 System 3

The GLPC for the system 3 are presented in the Figure 5.23. The system contain the well with almost the same performance lift curve, the wells are producing at lower production rate (less than 2000 STB/D) and the initial gas injection rate is zero.

In Table D.11 the first coefficient for all the wells are similar for both equations used in the optimisation. The deviation value is lower in average of 4% for all GAP model schematic. The system have the lowest deviation value comparing with other systems (Table D.3.6).

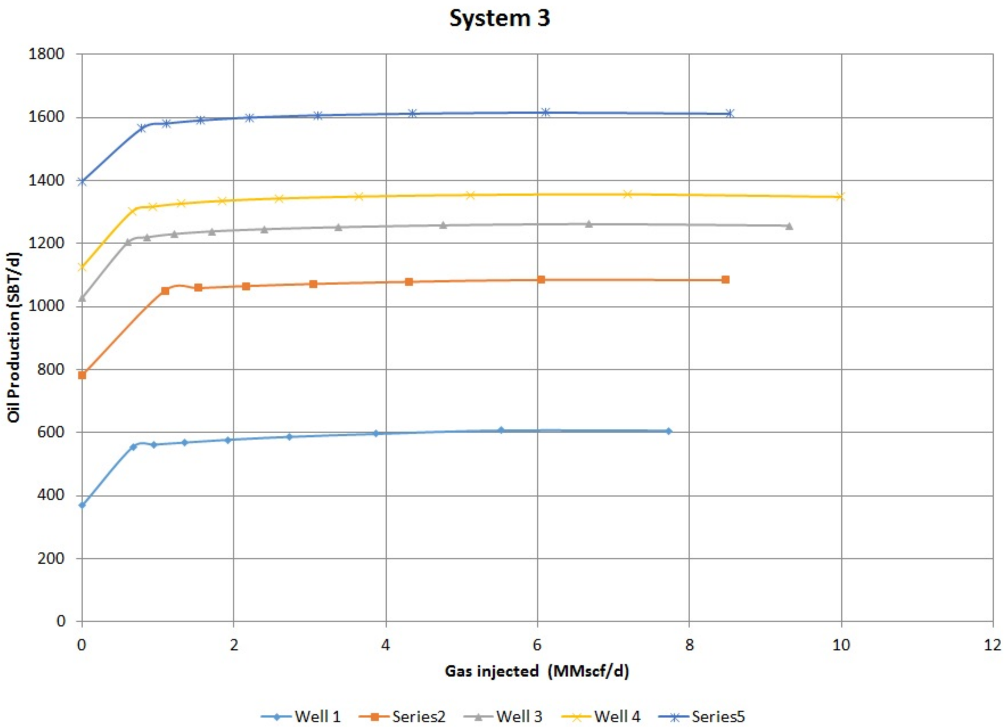


Figure 5.23: GLPC for system 3

5.2.4 System 4

The fourth system optimisation method 1 were done using the GLPC data for the wells in Table D.3. Well 1 of the system start with the value greater than zero and there is difference between the first coefficient in the equations (Table D.4).

The deviation between the method 1 and GAP-2 is very low comparing with another models(Table D.37).

If a comparison of the system 2 in section 5.2.2 the deviation is also lower when the GAP-2 is compared and the system also contain a well with gas injection rate greater than zero.

It was noted that for the system 2 the deviation value is greater than the deviation in system 4, due to the distance between the first coefficient equation.

The well in system 2 the coefficients are 177% distant from each other, and in the system the coefficients for the well are distant in 166%, having as base the value Alaracón equation coefficient.

Chapter 6

Conclusions and Recommendation

Conclusions

The optimisation of gas lifted well system is important because excessive gas injection reduces oil production and increases operation cost. Sometimes this optimisation is expensive when computational optimisation methods are chosen or recommended, then two different methods of optimisation were study to identify when the optimum oil production value for both are close to each other.

The present work was developed based on the network system of five gas lifted wells and different cases were modelled. Before the optimization calculation some simulation were done in PROSPER to find the GLPC. With this some conclusion can be taken as:

- Gas lift performance curve is a non-linear function of gas injected and oil produced for a particular well.
- The shape of the GLPC generated changes when some parameters as water cut, reservoir pressure, wellhead pressure, GOR and well equipment size are changed.
- Depending on the gas lift well design in PROSPER the gas lift performance curve have different response.
- For a particular well, when the value of the reservoir pressure increase the oil production rate also increase, because the wellhead pressure remains constant during the gas lift well design in PROSPER.
- For a well with high oil rate production more gas injection is needed to reach the maximum oil production of the same well.

After GLPC behaviour analysis in different condition, the data were used for the optimisation in method 1 and another using GAP (method 2). Therefore a comparison for the methods were presented in perceptual deviation calculation. Then it was possible to conclude that:

- The value of the optimum oil production for a group of well found using curve fitting technique is better approximation of the GAP optimisation values than using piecewise-linear optimisation.
- For a system containing well producing high amount of oil the perceptual deviation is high, i.e., the value optimum found using curve fitting or piecewise-linear programming differ more that 10% with a simple model in GAP (without any facilities system or pipeline).

- For a system with wells having lower gas injection and oil production rate in the GLPC generated the deviation is lower than 10%.

- For a system having a well that needs a gas injection greater than zero at the beginning the deviation is bigger than systems with initial data for gas injection equal to zero.

- If a system have one or more wells with initial gas injection rate greater than zero in GLPC the deviation is very lower (less than 5%) when GAP-2 model is used for comparison. Because the total oil for the GAP-2 model schematic is lower and approaches more to the value found using method 1.

- Using the first coefficient for the Alaracón et al. and Rashid et al. equation is possible to predict if the perceptual deviation between the total oil production using method 1 and method 2 is high or lower.

- The difference between the first coefficients of the Alaracón and Rashid can be one of the factor that may show the percentage of the deviation for a specific system. If the system have more than one well with different values in the first coefficient bigger will be the deviation more than 20% if the model in GAP has no facility system.

- For a system with wells having the first coefficient for the equations more close, less will be the deviation between the optimisation using GAP and method 1.

- Curve fitting technique using Rashid et. al. equation takes less time and iteration number comparing with other techniques in method 1.

- The optimisation for the system using the model schematic GAP-3 takes more time comparing with the another model, due to the number of pipelines in the system. This case the pressure loss changes and more time is necessary to converge the value.

- Deviation found for the case of injected gas per well increases proportional with the amount of gas available.

Recommendations

Since the gas lift method is one of the most used methods to solve production problem in the oil industries, it is highly recommended a study in the profit optimisation to see if this artificial methods is suitable for a certain system. For this specific case of gas lifted well a research in a system with more than five well and containing a facilities equipments as pipeline, compressor, etc is also recommended to see if the observations will be the same as in the present report.

The final general recommendation is for further studies having another artificial methods as a goal for the optimisation using the approach of constant wellhead pressure.

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Appendices

Appendix A

Well Modelling in PROSPER

PROSPER mean **PRO**duction and **S**ystem **PER**formance analysis software from Petroleum Experts Limiters.PROSPER can assist the production or reservoir engineer to predict tubing and pipeline hydraulics and temperatures with accuracy and speed.[15] Prosper is powerful sensitivity calculation features, can enables the handling of an already existing project, as well as the future utilization of equipment that make a difference in the project.

The following sub-chapter summarize how to build a well using the software PROSPER was described using the PROSPER software manual.[15]

A.1 Setting Up the Model

In order to design a gas lifted well, the gas lift option should be enable in the **Options|Options** screen:

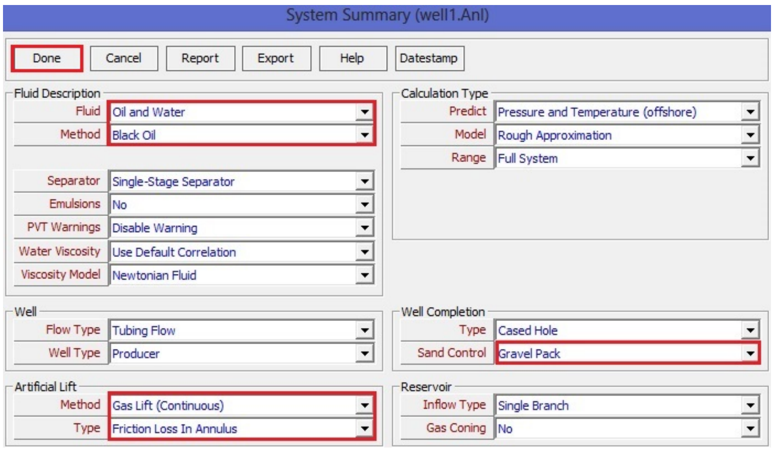


Figure A.1: System Summary for well

For this design, *Gas Lift (Continuous)* and *Friction Loss in Annulus* from the drop down menus. considering that during the gas flowing trough the annulus there is no pressure loss due to the friction.

A.2 Insetting PVT Data

The PVT data screen had been entered to describe the reservoir fluid properties. This value can be given by the laboratories tests.

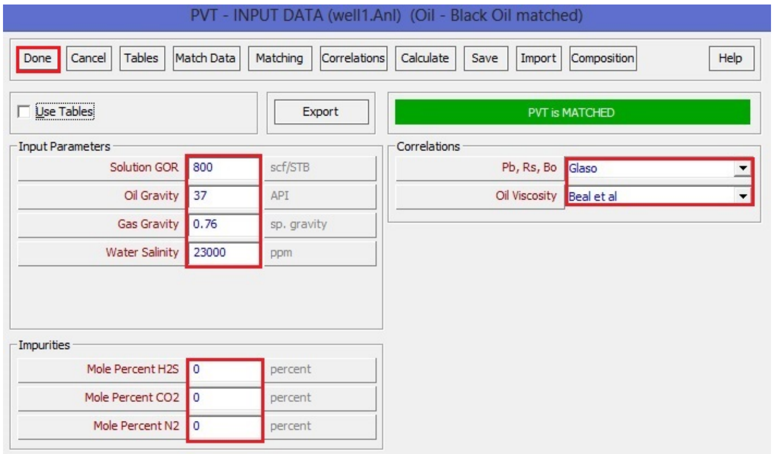


Figure A.2: Screen to insert the PVT Data

A.2.1 PVT Matching

When some test are done or data are available for a particular field, this data can be used and matched during the gas lift design.

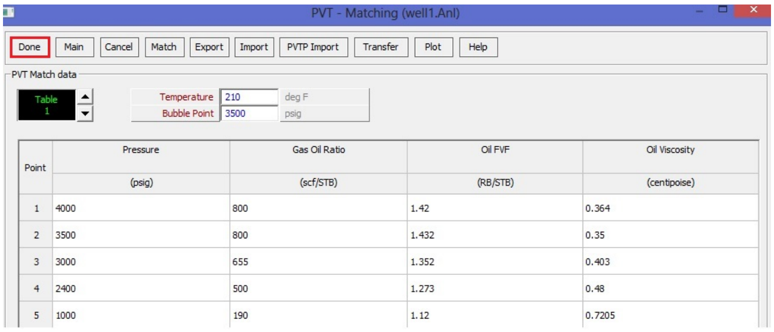


Figure A.3: Match Data screen to enter the laboratory data

A.2.1.1 Matching the correlations

After introduced the data a correlation for should be found, this can be done by selecting **Match** in the screen and then see the parameter 1 should the approximately 1 and the parameter 2 small number or zero.

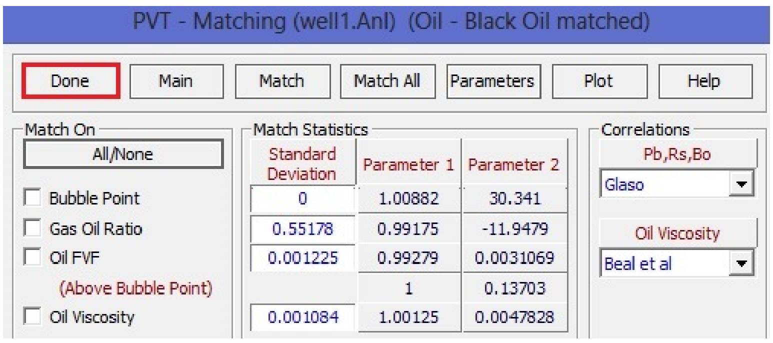


Figure A.4: Match Data screen to enter the laboratory data

A.3 Defining the Annulus

As the pressure drop due to the gas travelling in the annulus, the annulus definition should be considered. This can be done by selecting **System|Equipment(Tubing etc)**. Select **All|Edit** to be able to introduced the values for each section.

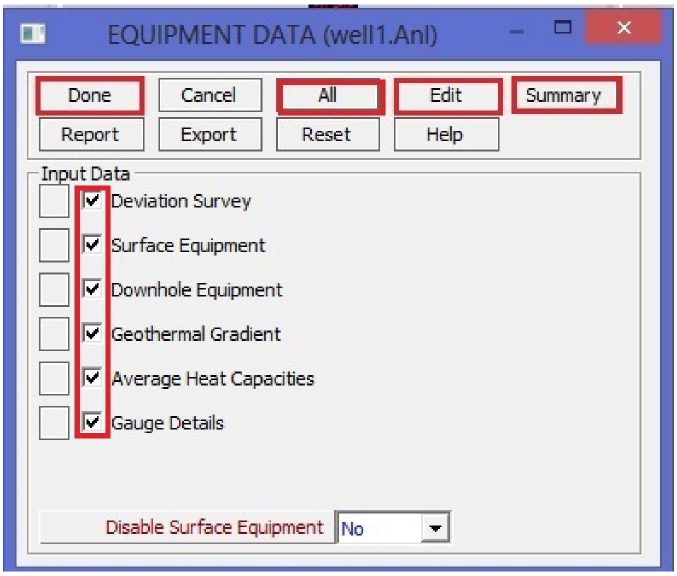


Figure A.5: Screen to select the equipment's

A.3.1 Deviation Survey

This section is to introduce that represents the refletion of the path the well takes to surface.

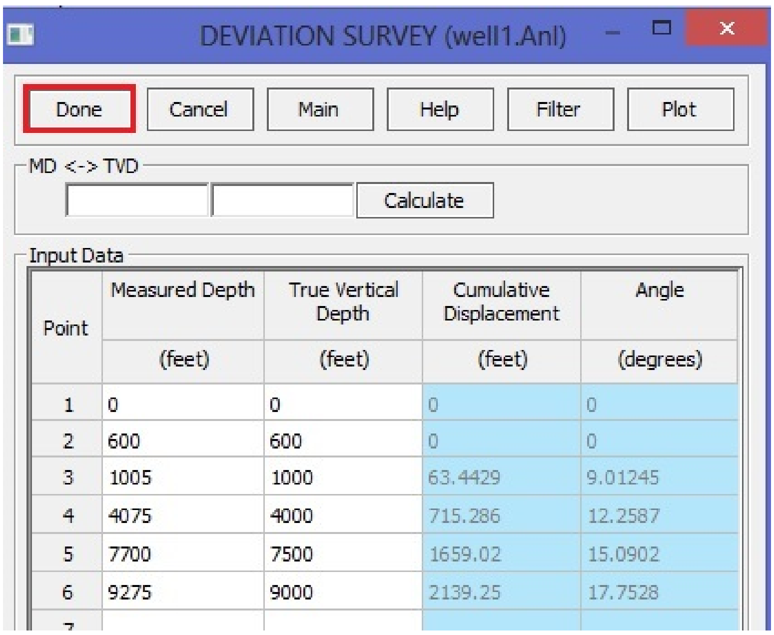


Figure A.6: Screen to insert the deviation survey data

A.3.2 Surface Equipment

This section is felled if there is any surface equipment in the model.

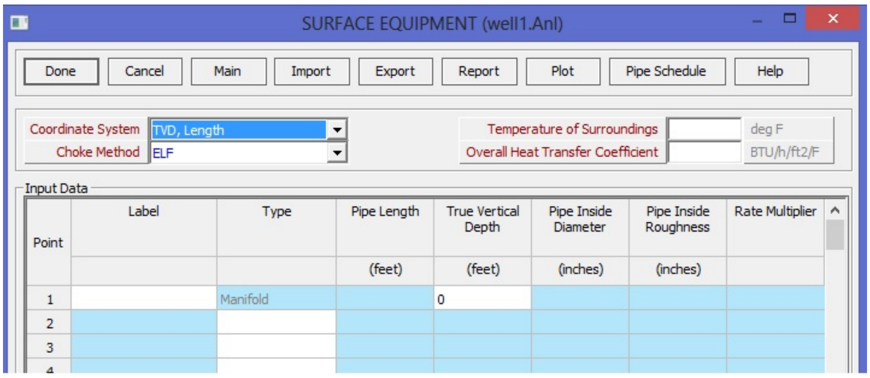


Figure A.7: Screen to insert the surface equipment data

A.3.3 Down-hole Equipment

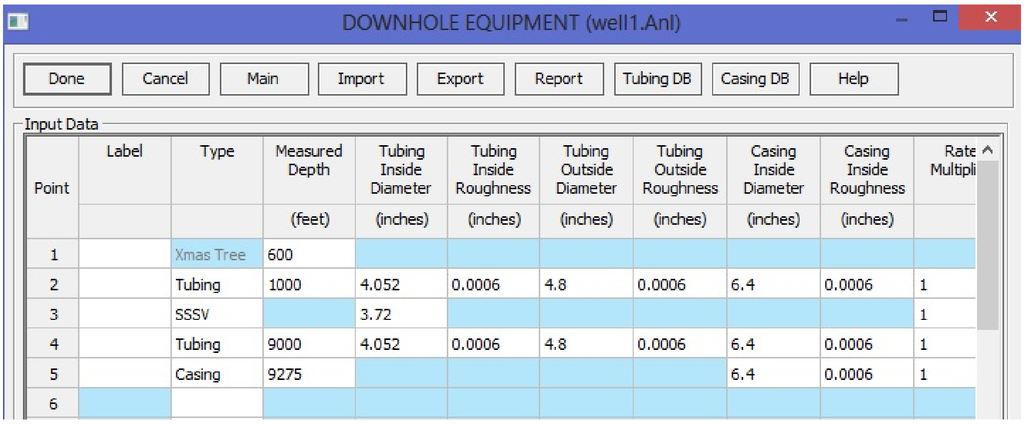


Figure A.8: Screen to insert the Down-hole equipment data

The screen is used input the values that specify the path through which the fluid will travel to surface.

A.3.4 Geothermal Gradient

In this section the temperature gradient of surrounding rock or atmosphere around the well.

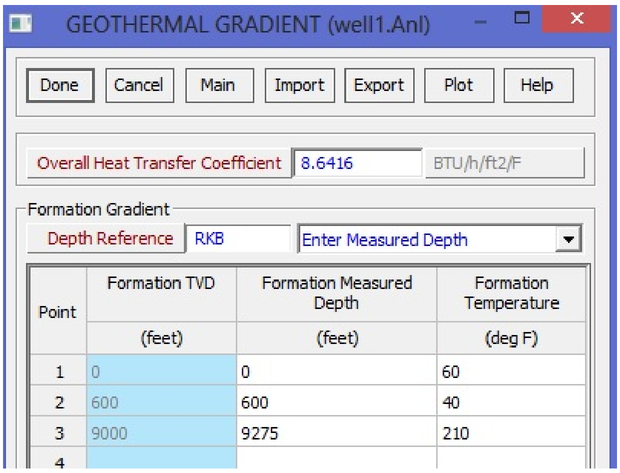


Figure A.9: Screen to insert the geothermal gradient data

Overall heat transfer coefficient = 8 BTU/hr/ft^2/^{o}F

A.3.5 Average Heat Capacities

A default values for the heat capacities of the fluids will be used for this well but they can be altered if necessary.

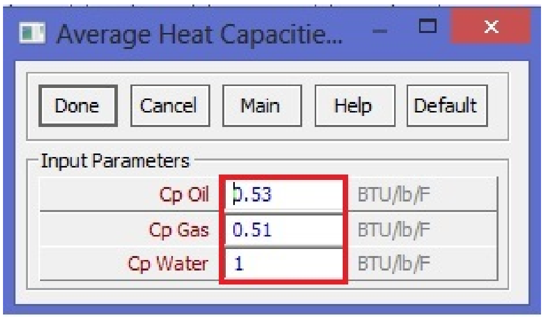


Figure A.10: Screen to insert the average heat capacity data

A.3.6 Gauge Details

If the gauge depths are specified for model, the value can be added in the screen below.

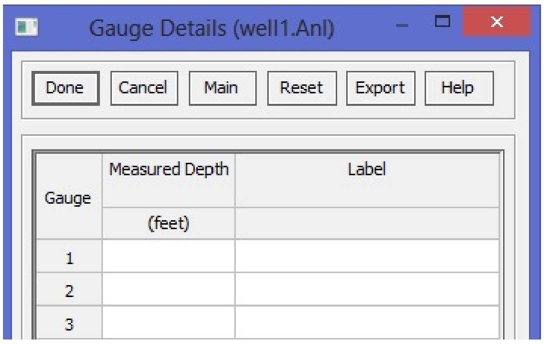
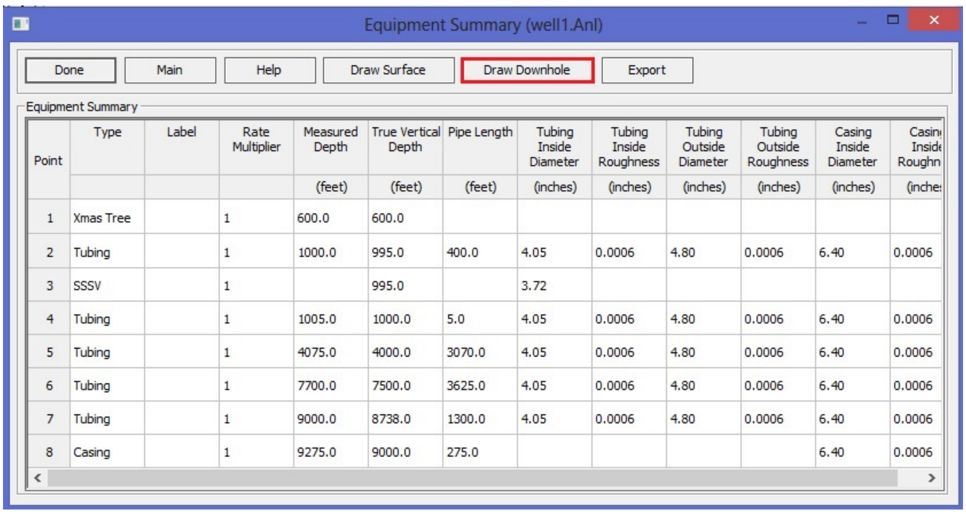


Figure A.11: Screen to insert the gauge details

A.3.7 Equipment Summary



Point	Type	Label	Rate Multiplier	Measured Depth (feet)	True Vertical Depth (feet)	Pipe Length (feet)	Tubing Inside Diameter (inches)	Tubing Inside Roughness (inches)	Tubing Outside Diameter (inches)	Tubing Outside Roughness (inches)	Casing Inside Diameter (inches)	Casin Insid Roughn (inche
1	Xmas Tree		1	600.0	600.0							
2	Tubing		1	1000.0	995.0	400.0	4.05	0.0006	4.80	0.0006	6.40	0.0006
3	SSSV		1		995.0		3.72					
4	Tubing		1	1005.0	1000.0	5.0	4.05	0.0006	4.80	0.0006	6.40	0.0006
5	Tubing		1	4075.0	4000.0	3070.0	4.05	0.0006	4.80	0.0006	6.40	0.0006
6	Tubing		1	7700.0	7500.0	3625.0	4.05	0.0006	4.80	0.0006	6.40	0.0006
7	Tubing		1	9000.0	8738.0	1300.0	4.05	0.0006	4.80	0.0006	6.40	0.0006
8	Casing		1	9275.0	9000.0	275.0					6.40	0.0006

Figure A.12: Equipment summary

Once the annulus has been defined, select **Done** to return to the *Equipment screen* and then **Done** to return to the main screen.

A.3.7.1 Draw Downhole

It is possible to see a drawing of the down-hole equipment by selecting **Draw Downhole**.

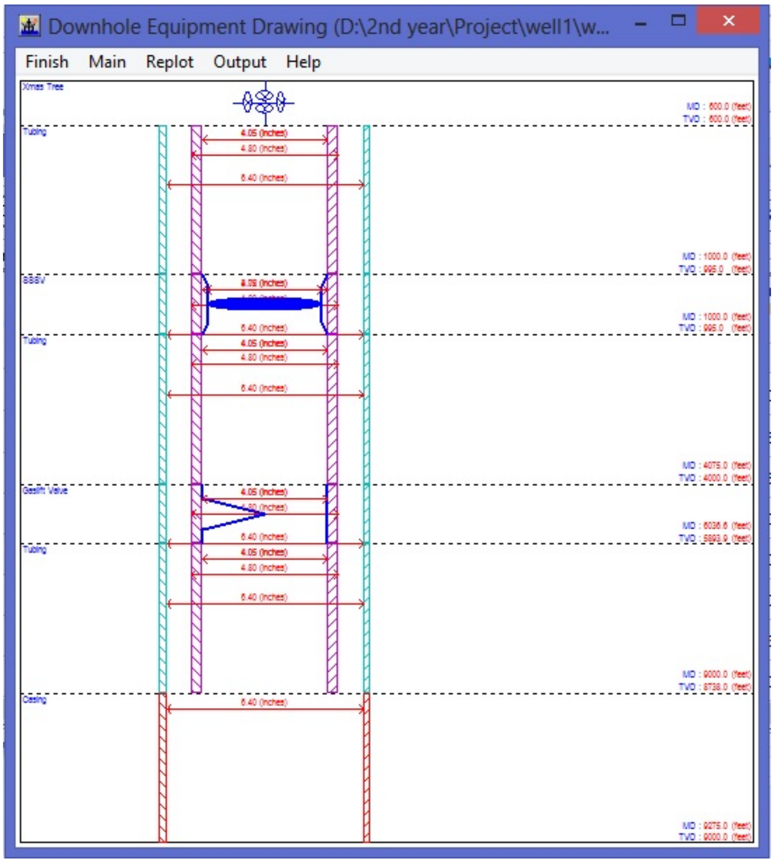


Figure A.13: Downhole Draw of the Well

A.4 Inputting IPR Data

The inflow from the reservoir and into the bottom of the well is defined in the IPR section. This can be done by selecting **System|Inflow Performance** to input the data in the screen.

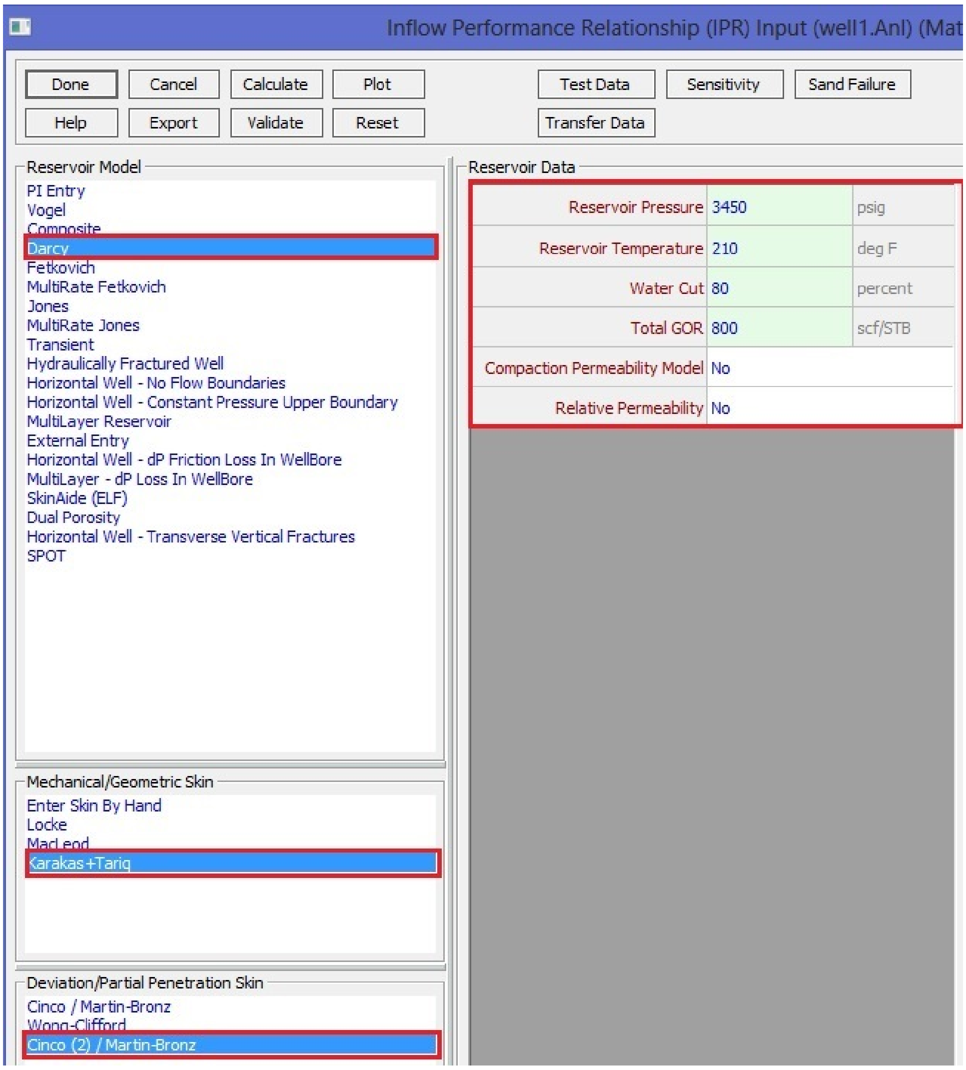


Figure A.14: Screen for inputting IPR data

A.4.1 Entering Data for the Darcy Model

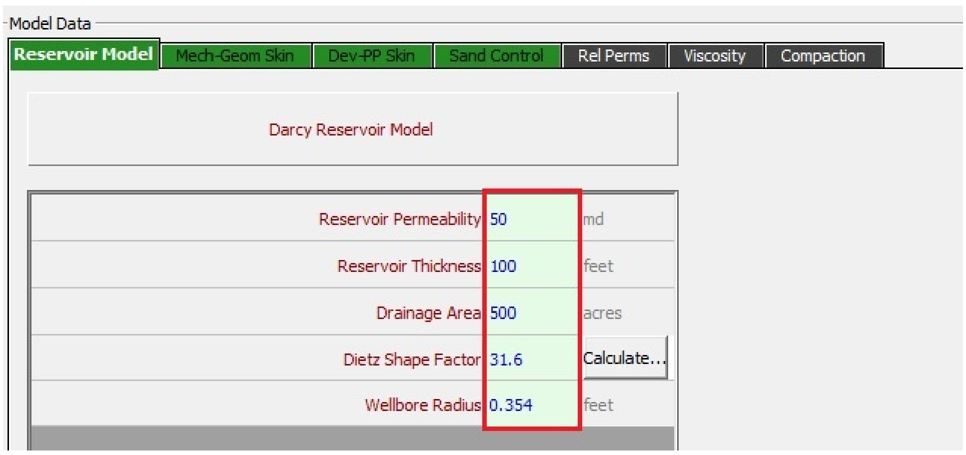


Figure A.15: Entering data for the Darcy model

A.4.2 Entering Data for Skin Models

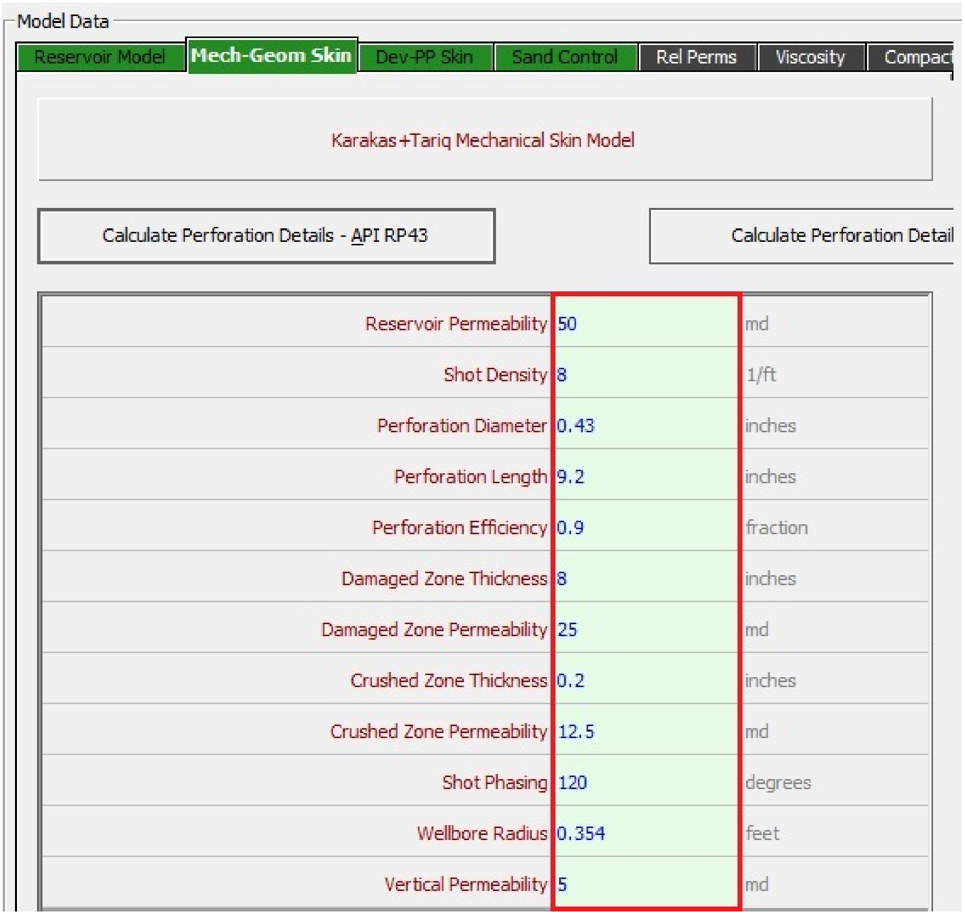


Figure A.16: Entering Data for Skin models

A.4.3 Entering Data for Sand Control

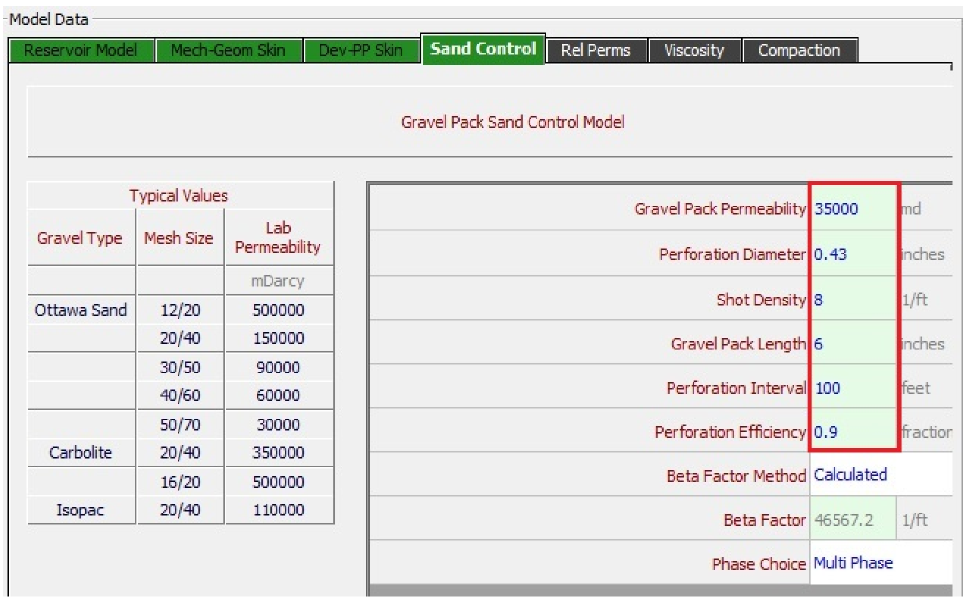


Figure A.17: Entering Data for sand control

A.5 Designing a Gas Lifted System

Before the design is carried out, the gas lift gas properties should be set. This can be done in the **System|Gas Lift Data** screen:

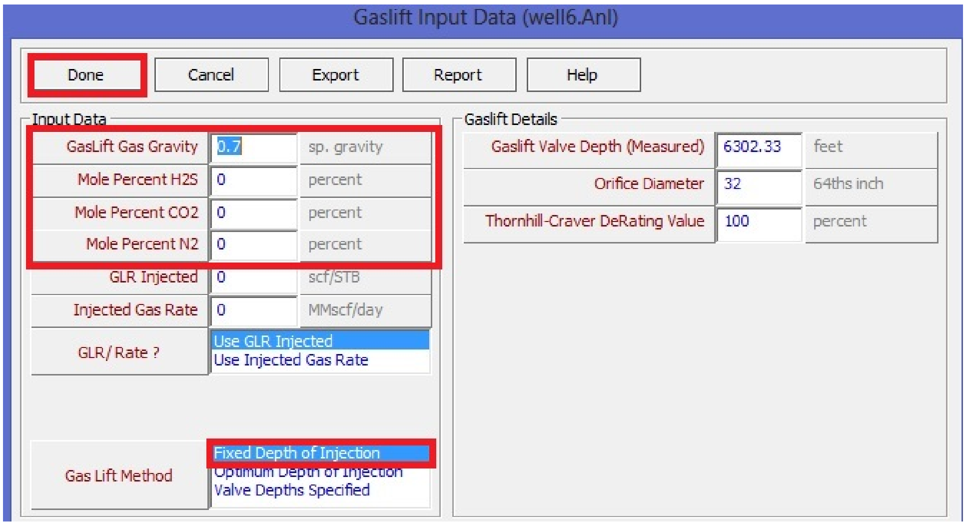


Figure A.18: Entering Data for the properties of gas injected

In this case a gas lift method is at *fixed depth of injection*. To return to the main screen press **Done**.

A.5.1 Entering the Design Criteria

To enter the design criteria to be used for the well, select **Design| Gas|New Well**:

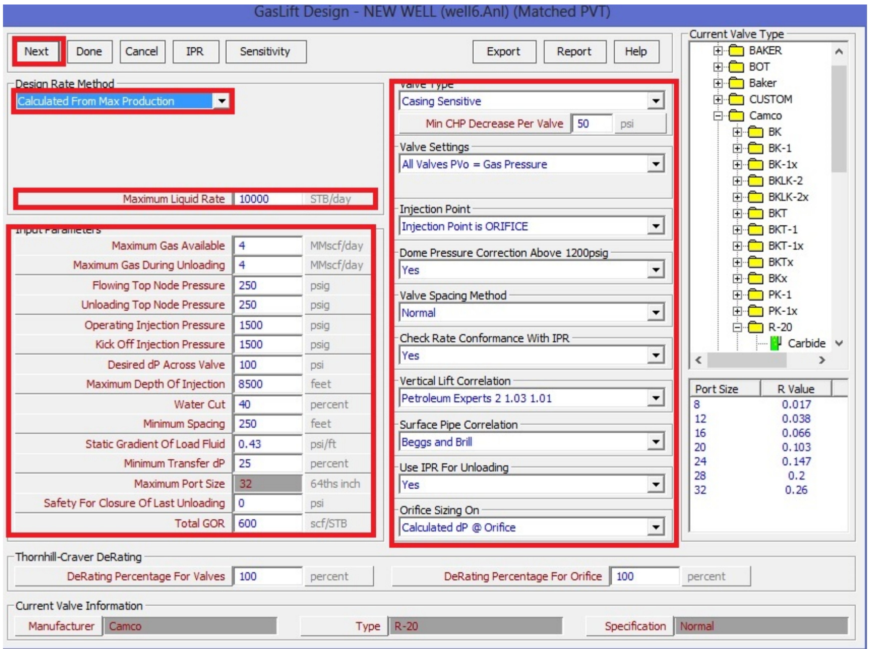


Figure A.19: Entering the well design criteria

Enter the design data shown above and select **Next**.

A.5.2 Finding the design Rate and the Valve Depths

Find the design rate is the first step to use during the design. This can be done by selecting **Get Rate**.

This will calculate the gas lift performance curve of produced oil rate against gas injection rate. The *Design Rate* will be calculated on the basis of the constraints placed in the previous screen, Represented in plot that can be seen by selecting the **Plot**.

With the design rate found, the valve depth can be calculated by selecting **Design**.

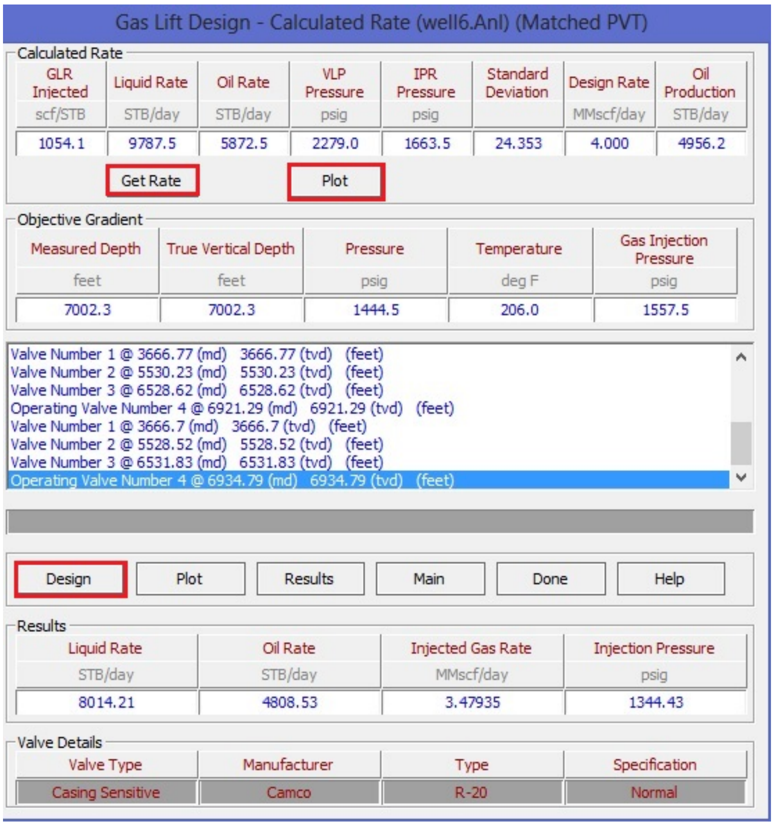


Figure A.20: The design rate and valve depths

Appendix B

Well Data Design in PROSPER

B.1 IPR

Table B.1: IPR data for Well 1 and Well 2

Parameter	Unit	Well 1	Well 2
Reservoir Pressure	psig	3026	3700
Reservoir Temperature	^{o}F	250	210
Total GOR	scf/STB	800	500

B.2 PVT Data

This is the preliminary PVT data which has been received from the lab to characterise the fluid as well as results from a flash calculation.

Table B.2: PVT Data for Well 1 and Well 2

Parameter	Unit	Well 1	Well 2
GOR	scf/STB	500	800
Oil gravity	^{o}API	39	37
Gas specific gravity	air=1	0.798	0.76
Water salinity	ppm	100000	23000
Mole H2S	%	0	0
Mole CO2	%	0	0
Mole N2	%	0	0

Flash Experiment Data

Table B.3: Temperature and pressure in the lab test Well 1

Temperature of test	250^{o}F
Bubble Point at test temperature	2200psi

Table B.4: Parameters measured in the Lab

Pressure	GOR	Oil FVF	Viscosuty
psig	scf/STB	STB/RB	cp
2200	500	1.32	0.4

Table B.5: Temperature and pressure in the lab test Well 2

Temperature of test	210^{o}F
Bubble Point at test temperature	3500psi

Table B.6: Parameters measured in the Lab

Pressure	GOR	Oil FVF	Viscosuty
psig	scf/STB	STB/RB	cp
4000	800	1.42	0.364
3500	800	1.432	0.35
3000	655	1.352	0.403
2400	500	1.273	0.48
1000	190	1.12	0.7205

B.3 Completion Data

The following data describes the casing and the annulus within the wells

Table B.7: Completion Data well 1

Type	MD	Tubing In Diam.	Tubing In Roughness	Casing In Diam.	Casing In Roughness
	(ft)	(Inches)	(Inches)	(Inches)	(Inches)
Xmas Tree	600				
Tubing	2999.9	5.01	0.0006		
SSSV		3.72			
Tubing	7900	5.01	0.0006		
Casing	8000			6.40	0.0006

Table B.8: Completion Data well 2

Type	MD	Tubing Inside Diameter	Tubing Outside Diameter	Tubing Inside/ Outside Roughness	Casing Inside Diameter	Casing Inside Roughness	Rate Multiplier
	(ft)	(Inches)	(Inches)	(Inches)	(Inches)	(Inches)	
Xmas Tree	600						1
Tubing	1000	4.052	4.8	0.0006	6.4	0.0006	1
SSSV		3.72					1
Tubing	8900	4.052	4.8	0.0006	6.4	0.0006	1
Casing	9000				6.4	0.0006	1

B.4 Gas Lift Design Criteria

The following criteria has been set for the gas lift design.

Table B.9: Input Parameters for the gas lift design

Parameters	**Unit**	**Well 1**	**Well 2**
Design Rate Method	Calculated From Max Prod.		
Maximum Liquid Rate	STB/day	6500	1500
Maximum Gas Available	MMscf/day	5	10
Maximum Gas During Unloading	MMscf/day	5	10
Flowing Top Node Pressure	psig	600	200
Unloading Top Node Pressure	psig	600	200
Operating Injection Pressure	psig	2000	1000
Kick Off Injection pressure	psig	2000	1000
Desired dp across valve	psi	100	100
Maximum depth of injection	ft	8000	7800
Water cut	%	15	40
Minimum Spacing	ft	250	250
Static gradient of load fluid	psi/ft	0.45	0.41
Minimum transfer dp	%	25	0
Safety for closure of last unloading valve	psi	0	50
Minimum CHP decrease per valve	psi	50	50

Table B.10: Design options for a valve

Design options for a valve	
Valve type	Casing sensitive
Valve Setting	All valve PVo=gas pressure
Injection point	Injection point ORIFICE
Dome pressure correlation above 1200psig	Yes
Valve spacing procedure	Normal
Check rate conformance with IPR	Yes
Vertical lift correlation	Petroleum Experts 2
Surface pipe correlation	Beggs and Brill
Use IPR for unloading	Yes
Orifice sizing on	Calculated dp @ orifice

Table B.11: Valve selection

Valve Selection	
Manufacturer	Camco
Valve type	R-20
Valve spec	Normal

Appendix C

Optimisation Modelling in GAP

GAP is used to simulate and perform a non-linear optimisation to allocate the gas for gas lifted wells to maximise the revenue or oil/gas production while honouring constraints at any level in the system. The following sub-chapter summarize how to build a optimisation modelling in GAP was described using the GAP software manual.[?]

C.1 Define GAP System Options

This option allows setting up overall system parameters.

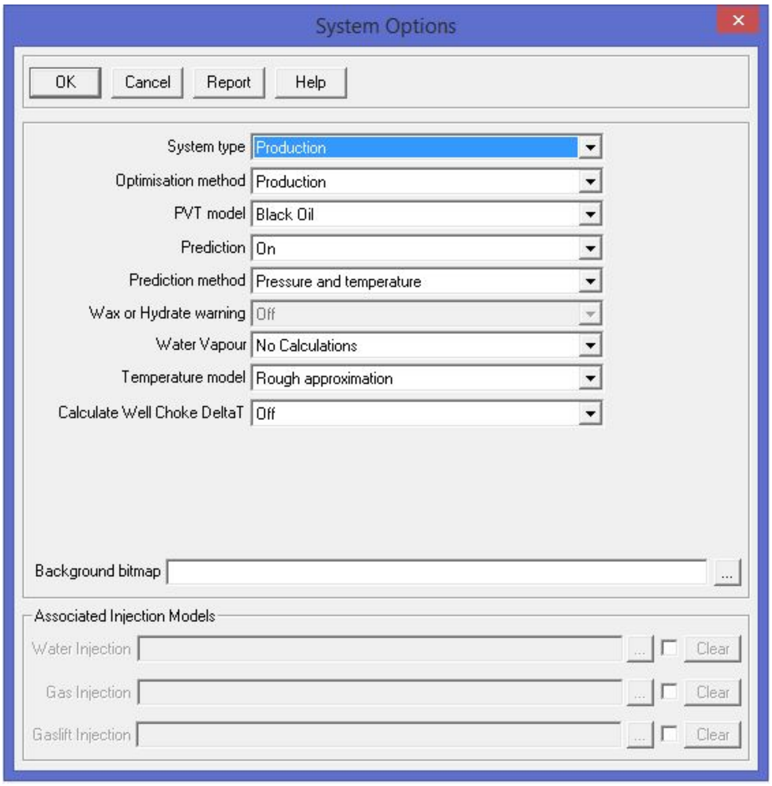


Figure C.1: System Options screen

C.2 Define GAP Model Schematically

This section is need to design the system. This include all components or elements used in the model. The properties of the components are entered using PROSPER and can be easily added and deleted.

Figure C.2: Components/equipment toll-bar

C.3 Define the Well

In this step the physical characteristics of the well shall be specified.

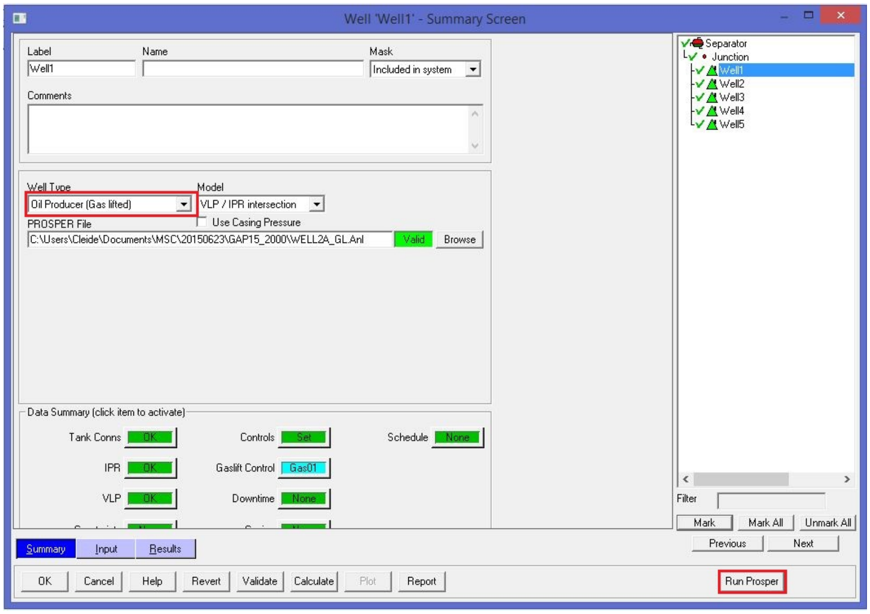


Figure C.3: Well Specification Screen

C.4 Calculate the Well IPR and VLP

The IPR and VLP data can be automatically generate in this section. From the main GAP menu Select **Generate|Generate Well IPRs or VLPs with PROSPER|All|Generate**

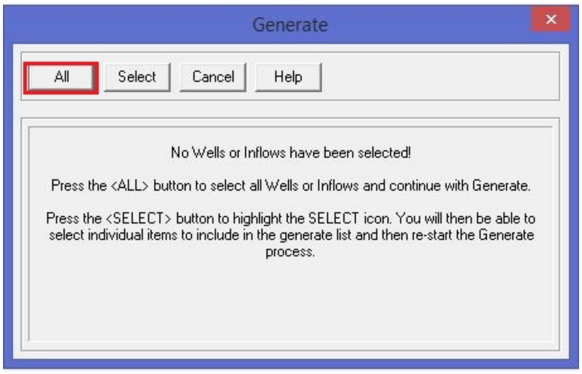


Figure C.4: Generate IPR and VLP screen

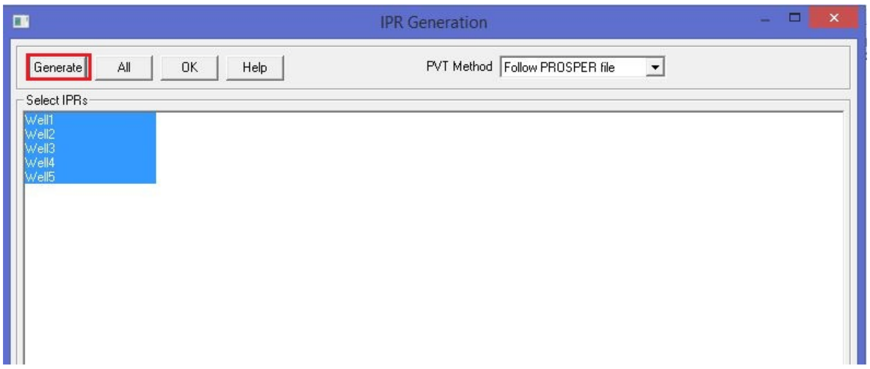


Figure C.5: IPR generate screen

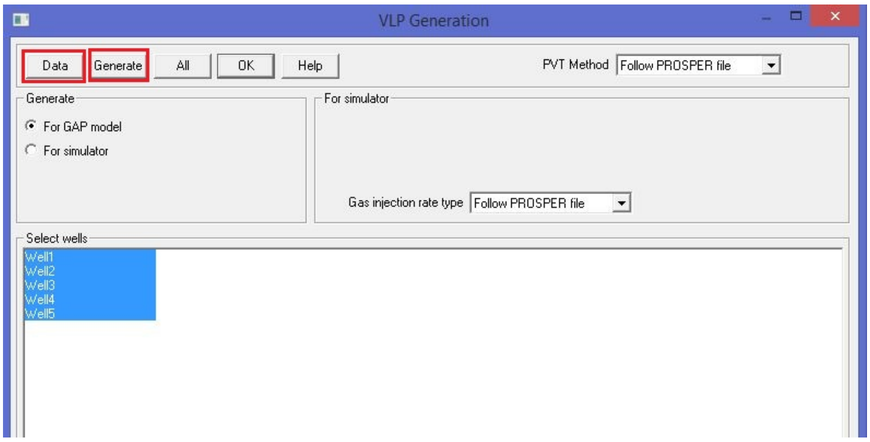


Figure C.6: VLP generate screen

The VLP curve is generate to a specific ranges of data. PROSPER is called up to load the sensitivity values already stored within it. The following sensitivity values:

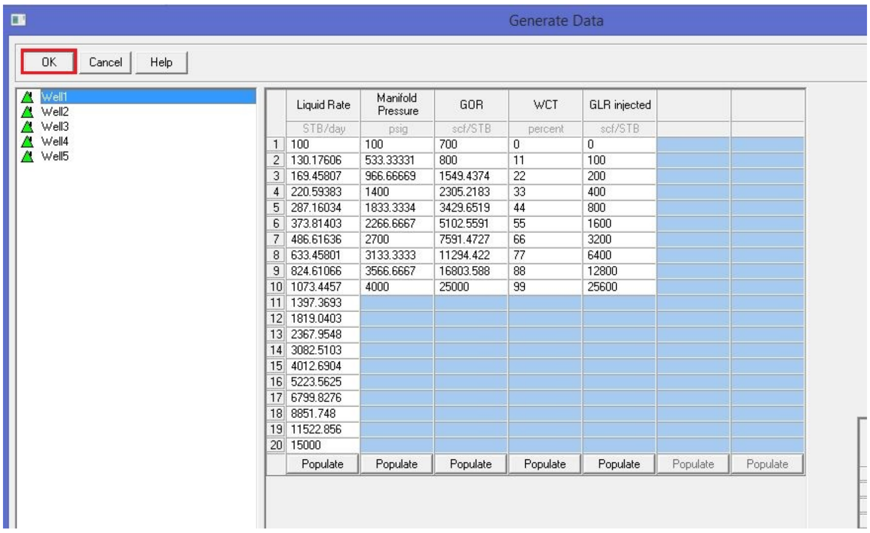


Figure C.7: Generate data for VLP

The VLP can also be generated within the PROSPER software and then imported to GAP. In case of Pipeline the definition is needed.

C.5 Define the Pipelines

To define the pipelines acess the pipe summary screen below by double-clicking on the link that joins the WH and the junction or junction and setpoint.

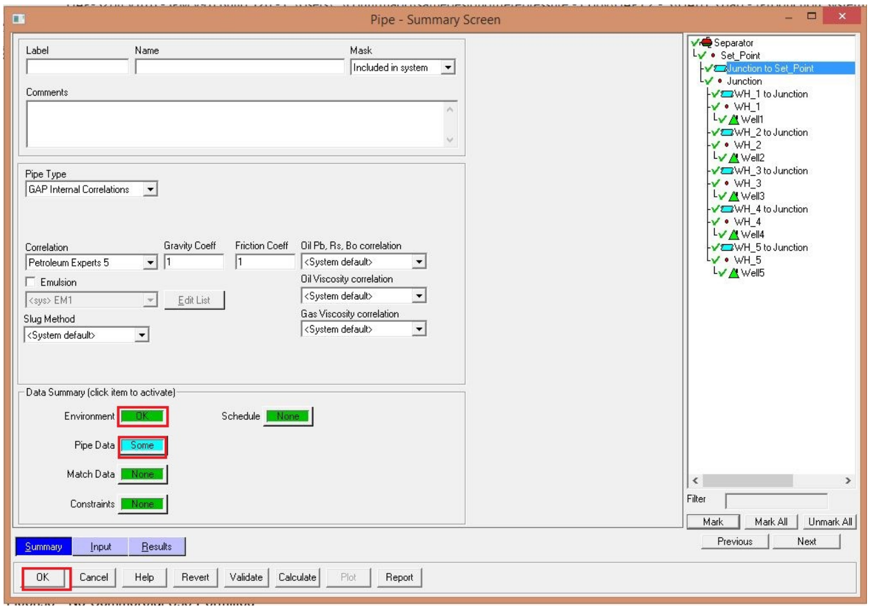


Figure C.8: Pipeline definition screen

Make the following changes:
Pipeline model : GAP Internal Correlation
Correlation : Petroleum Experts 5
Gravity Coefficient : 1
Friction Coefficient : 1

Environment

In the screen select ***Environment*** to have access to the pipeline environment and make the following changes:
Surface Temperature : 50 deg/F
Overrall Heat Transfer Coefficient : 8 Btu/h/ft
Oil Heat Capacity : 0.53 Btu/lb/F (default)
Gas Heat Capacity : 0.51 Btu/lb/F (default)
Water Heat Capacity : 1 Btu/lb/F (default)

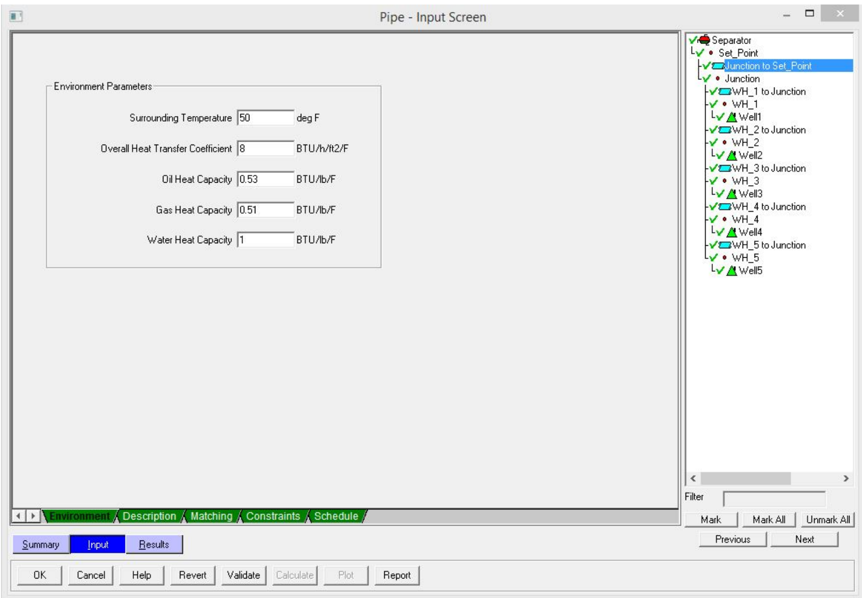


Figure C.9: Pipeline environment screen

Pipeline Description

Select the ***Description*** to define the pipeline dimensions in the screen.

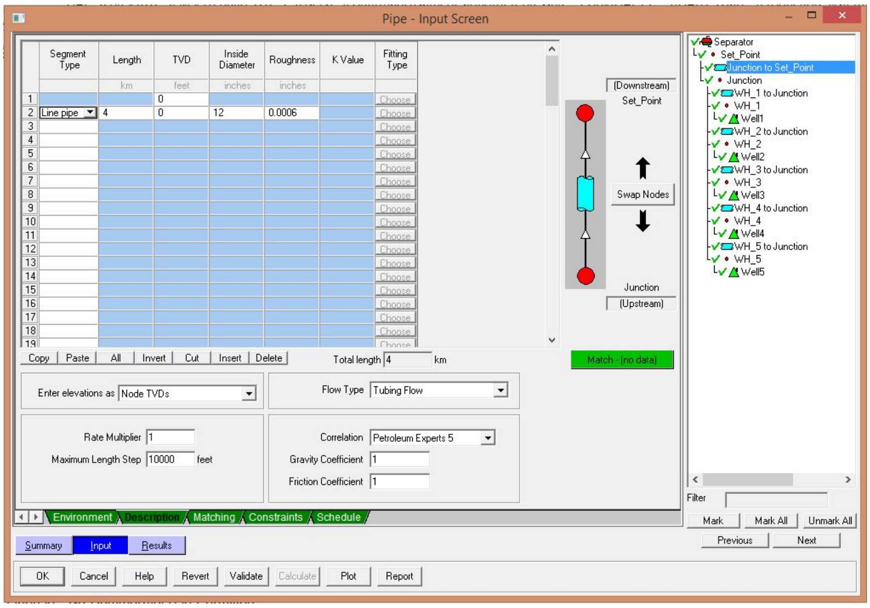


Figure C.10: Pipeline description screen

Once the data has been entered click *Validate* to check if the data entered is valid or not. After this click on **OK** to retorn to the GAP main screen.

Repeat this procedure for all the wells lines in the system.

C.6 Calculate Production Given total lift available

To perform the optimisation from the system given a total amount of gas lift available, click on |**Solve Network** in the main menu and the enter different amount of gas available.

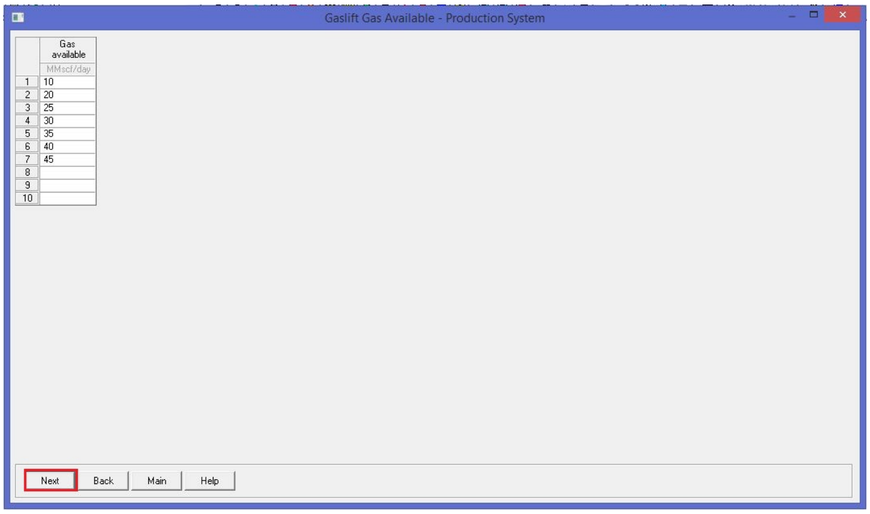


Figure C.11: Gas available screen input

Then | **Next** and production will be determined for the separator pressure introduced in the screen.

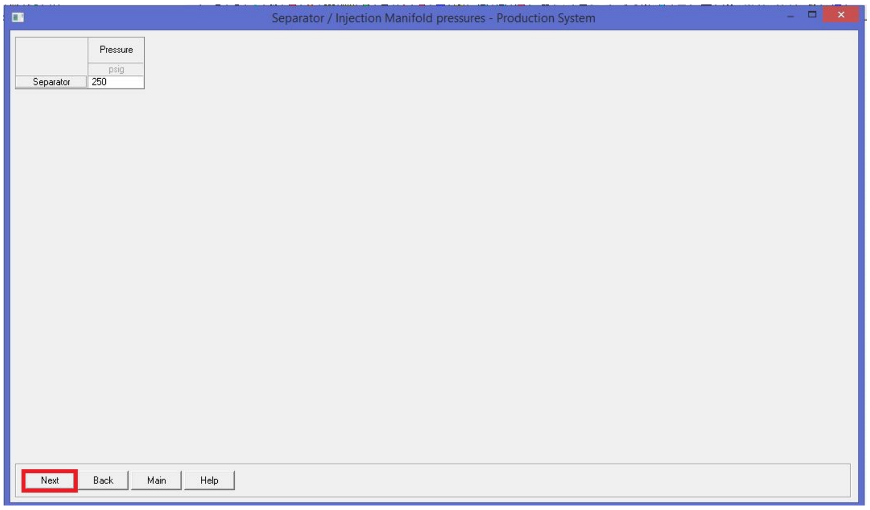


Figure C.12: Separator pressure screen input

Then click on |**Next**|**Calculate** check box ***Optimise with all Constraints*** before the calculation is started.

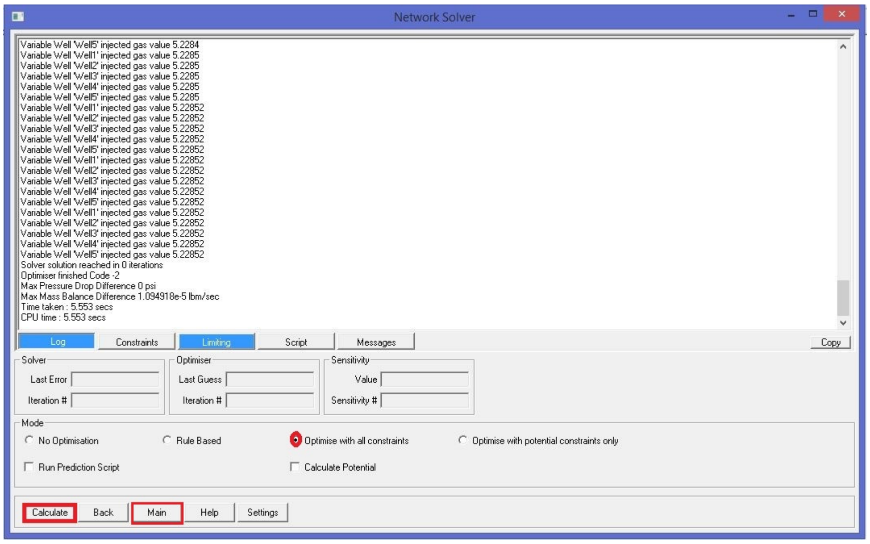


Figure C.13: Optimisation screen

C.7 Result analysis

To see and export the result of the optimised injection of increasing of lift gas, click on **Results|Summary|All Wells**

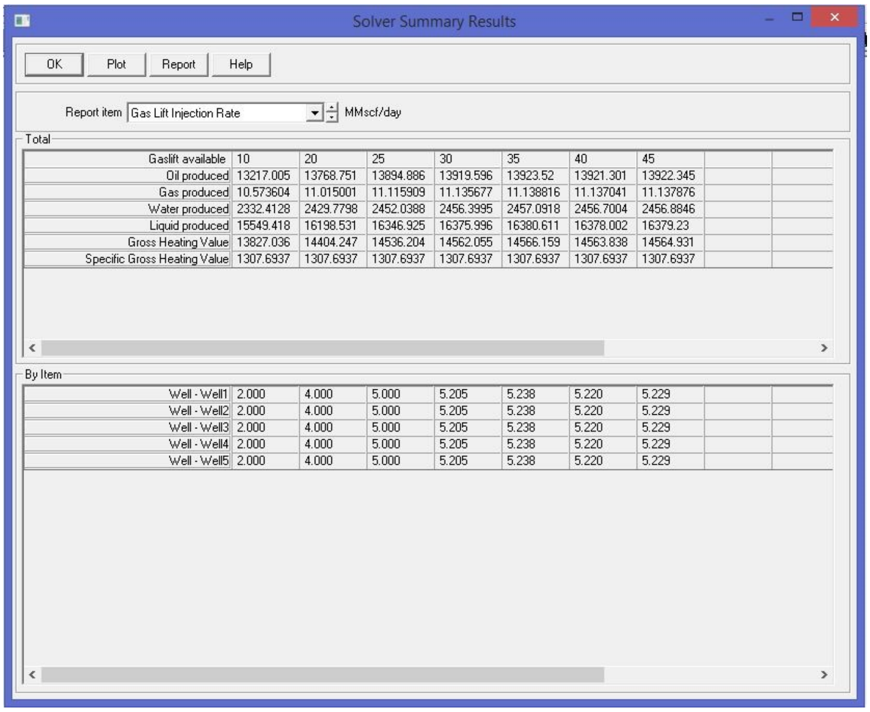


Figure C.14: Summary results screen

Appendix D

Results from the Simulations and Calculated

D.1 Data generate from PROSPER

D.1.1 Same layout 1: For different reservoir pressure

For the calculation each data were used five times, i.e. the gas lift performance data in well 1 = well 2 = well 3 = well 4 = well 5.

Table D.1: Data from PROSPER for different reservoir pressure layout 1

S 1-1; PR=2000psig		**S 1-2; PR=3026psig**		**S 1-3; PR=3450psig**	
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D
1.7479E-08	368.23	0.00	782.58	0.00	1027.88
0.67	555.42	1.09	1050.55	0.60	1203.87
0.95	561.73	1.54	1058.09	0.86	1219.56
1.35	568.38	2.17	1064.97	1.21	1229.99
1.91	576.83	3.05	1071.57	1.71	1238.35
2.72	586.27	4.30	1078.28	2.40	1245.43
3.87	595.56	6.05	1084.36	3.38	1251.70
5.52	606.50	8.47	1083.80	4.76	1257.53
7.72	606.00			6.68	1261.46
				9.31	1256.60
S 1-4; PR=4000psig		**S 1-5; PR=6200psig**			
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D		
0.00	1235.64	0.00	1789.63		
0.71	1408.42	0.97	1940.12		
1.00	1423.60	1.37	1953.11		
1.41	1433.90	1.93	1961.88		
1.99	1443.12	2.71	1969.87		
2.80	1450.30	3.81	1976.17		
3.93	1456.07	5.35	1980.43		
5.52	1460.41	7.49	1981.24		
7.73	1460.37	10.43	1970.41		

*__S 1-n__: where 1 is the layout well and n the number of system created by changing the reservoir pressure

Table D.2: Equation coefficient in layout 1

System	Equation	**C1**	**C2**	**C3**	**C4**
1-1	Alaracón	384.3	-198.8	10.83	516.5
	Rashid	383.4	216.7	-51.04	
1-2	Alaracón	790.2	-220.5	10.69	623.3
	Rashid	794.8	281.7	-64.9	
1-3	Alaracón	1050	-160.3	7.443	455.4
	Rashid	1048	207.8	-47.56	
1-4	Alaracón	1246	-190.5	10.12	502.1
	Rashid	1247	214.8	-51.42	
1-5	Alaracón	1797	-93.15	3.559	313
	Rashid	1798	165.9	-35.68	

D.1.2 Same layout 2 : For different reservoir pressure

For the calculation each data were used five times, i.e. the gas lift performance data in well 1 = well 2 = well 3 = well 4 = well 5.

Table D.3: Data from PROSPER for different reservoir pressure layout 2

S 2-1; PR=2000psig		**S 2-2; PR=3100psig**		**S 2-3; PR=3700psig**	
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D
0.67	459.71	0.00	776.38	0.00	2778.33
1.10	670.51	0.48	1810.77	1.32	3834.55
2.03	883.73	0.81	2198.96	1.97	4077.07
3.17	982.74	1.31	2526.32	2.89	4281.73
4.82	1068.45	2.05	2830.86	4.21	4458.22
7.10	1124.60	3.14	3091.06	6.08	4593.53
10.17	1150.23	4.66	3274.17	8.64	4663.35
14.17	1145.37	6.69	3357.27	12.07	4655.13
		9.41	3376.72		
		13.13	3364.91		
S 2-4; PR=4500psig		**S 2-5; PR=6200psig**			
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D		
0.00	4892.29	0.00	8104.70		
0.88	5293.62	1.38	8296.55		
1.26	5407.57	1.95	8356.48		
1.81	5548.31	2.75	8426.24		
2.61	5711.83	3.89	8504.75		
3.75	5857.90	5.49	8574.66		
5.37	5991.09	7.74	8632.10		
7.64	6089.24	10.86	8652.93		
10.78	6133.31	15.17	8632.16		
14.96	6080.37				

* **S 2-n**: where 2 is the layout well and n the number of system created by changing the reservoir pressure

Table D.4: Equation coefficient in layout 2

System	Equation	**C1**	**C2**	**C3**	**C4**
2-1	Alaracon	82.66	-190.4	4.822	1029
	Rashid	-57.51	807.9	-131.8	
2-2	Alaracon	885	-646.9	19.25	2903
	Rashid	761.1	1861	-320.8	
2-3	Alaracon	2784	-267.4	6.078	1641
	Rashid	2762	1201	-188	
2-4	Alaracon	4885	-28.58	-1.435	700.9
	Rashid	4816	692.6	-90.74	
2-5	Alaracon	8100	28.32	-1.974	198.5
	Rashid	8073	270.3	-30.12	

D.1.3 Same layout well 3

Table D.5: Data from PROSPER for layout well 3

Well 1	
Qg,MMscf/D	Qo,STB/D
0.2581	345.75
0.40	481.47
0.88	752.24
1.58	964.07
2.60	1131.36
3.93	1222.76
5.76	1280.99
8.17	1298.57
11.43	1296.73

D.1.4 Different layout system 1

Table D.6: Data generated in PROSPER for system 1

Well 1		Well 2		Well 3	
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D
5.06E-04	595.07	0.00	2778.33	0.00	3722.41
0.61	927.47	1.32	3834.55	0.69	4137.82
0.99	1071.03	1.97	4077.07	0.99	4246.06
1.57	1214.56	2.89	4281.73	1.43	4371.94
2.46	1354.76	4.21	4458.22	2.06	4504.68
3.73	1468.87	6.08	4593.53	2.97	4637.96
5.51	1550.86	8.64	4663.35	4.26	4751.86
7.83	1572.68	12.07	4655.13	6.06	4826.34
10.89	1563.04			8.53	4855.58
				11.84	4812.57
Well 4		**Well 5**			
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D		
0.00	782.58	0.00	817.30		
1.09	1050.55	1.09	1054.28		
1.54	1058.09	1.54	1061.60		
2.17	1064.97	2.17	1068.31		
3.05	1071.57	3.06	1074.75		
4.30	1078.28	4.31	1081.33		
6.05	1084.36	6.07	1087.23		
8.47	1083.80	8.49	1086.40		

Table D.7: Equation coefficient in system 1

Well	Equation	**C1**	**C2**	**C3**	**C4**
1	Alaracon	594.9	-145.8	3.011	888.3
	Rashid	537.3	675.3	-108.6	
2	Alaracon	2784	-267.4	6.078	1641
	Rashid	2762	1201	-188	
3	Alaracon	3729	-128.1	1.672	927.8
	Rashid	3669	745.4	-117	
4	Alaracon	790.2	-220.5	10.69	623.3
	Rashid	794.8	281.7	-64.9	
5	Alaracon	824	-191.7	9.233	546.8
	Rashid	827.8	249.6	-57.11	

D.1.5 Different layout system 2

Table D.8: Data generated in PROSPER for system 2

Well 1		Well 2		Well 3	
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D
5.03E-04	593.25	0.26	345.75	0.00	471.80
0.61	925.00	0.40	481.47	0.48	959.09
0.99	1068.85	0.88	752.24	0.76	1080.34
1.57	1213.30	1.58	964.07	1.18	1203.76
2.46	1354.50	2.60	1131.36	1.83	1333.98
3.73	1466.92	3.93	1222.76	2.79	1454.94
5.50	1547.77	5.76	1280.99	4.17	1550.50
7.82	1569.98	8.17	1298.57	6.08	1616.22
10.87	1560.12	11.43	1296.73	8.64	1639.78
				11.95	1618.93
Well 4		**Well 5**			
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D		
0.00	417.90	0.00	478.81		
0.41	812.32	0.42	840.71		
0.64	916.59	0.65	935.66		
1.02	1036.97	1.02	1044.44		
1.59	1161.99	1.59	1158.19		
2.45	1273.50	2.42	1258.95		
3.67	1365.13	3.62	1345.77		
5.36	1423.46	5.25	1394.46		
7.63	1447.57	7.43	1408.77		
10.60	1436.65	10.29	1394.30		

Table D.9: Equation coefficient in system 2

Well	Equation	**C1**	**C2**	**C3**	**C4**
1	Alaracon	592.8	-147.6	3.083	892.3
	Rashid	535.4	676.4	-109	
2	Alaracon	138	-299	9.239	1339
	Rashid	-106.6	1066	-196	
3	Alaracon	533	-284.2	8.838	1264
	Rashid	473.1	820	-142.4	
4	Alaracon	468.1	-294.8	10.16	1209
	Rashid	407.5	758.5	-136.6	
5	Alaracon	519.2	-275.6	9.479	1121
	Rashid	464.4	703.7	-129.4	

D.1.6 Different layout system 3

Table D.10: Data generated in PROSPER for system 3

Well 1		Well 2		Well 3	
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D
1.7479E-08	368.23	0.00	782.58	0.00	1027.88
0.67	555.42	1.09	1050.55	0.60	1203.87
0.95	561.73	1.54	1058.09	0.86	1219.56
1.35	568.38	2.17	1064.97	1.21	1229.99
1.91	576.83	3.05	1071.57	1.71	1238.35
2.72	586.27	4.30	1078.28	2.40	1245.43
3.87	595.56	6.05	1084.36	3.38	1251.70
5.52	606.50	8.47	1083.80	4.76	1257.53
7.72	606.00			6.68	1261.46
				9.31	1256.60
Well 4		**Well 5**			
Qg,MMscf/D	Qo,STB/D	Qg,MMscf/D	Qo,STB/D		
0.00	1126.37	0.00	1397.49		
0.65	1300.79	0.79	1565.41		
0.93	1316.23	1.11	1580.58		
1.31	1326.62	1.57	1590.59		
1.84	1335.17	2.20	1599.36		
2.59	1342.82	3.10	1606.46		
3.64	1348.87	4.35	1611.77		
5.12	1353.86	6.11	1615.09		
7.178	1355.90	8.532	1611.72		
9.99	1347.89				

Table D.11: Equation coefficient in system 3

Well	Equation	**C1**	**C2**	**C3**	**C4**
1	Alaracon	384.3	-198.8	10.83	516.5
	Rashid	383.4	216.7	-51.04	
2	Alaracon	790.2	-220.5	10.69	623.3
	Rashid	794.8	281.7	-64.9	
3	Alaracon	1050	-160.3	7.443	455.4
	Rashid	1048	207.8	-47.56	
4	Alaracon	1147	-140	6.019	420.3
	Rashid	1145	201.4	-45.07	
5	Alaracon	1407	-153.7	7.373	436.9
	Rashid	1408	200.8	-46.3	

D.2 Optimisation Value of Total Oil Production

D.2.1 Same layout well 1 : For different reservoir pressure

Table D.12: Optimum oil production for system 1-1

System 1-1						
Gas Ava.	**Piecewise**		**Alarcon**		**Rashid**	
	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	2889.16	10.00	2987.27	10.00	2938.90
20.00	20.00	2982.01	13.28	3011.30	20.00	3063.20
25.00	25.00	3015.17	13.28	3011.30	22.53	3067.05
30.00	27.61	3032.49	13.28	3011.30	22.53	3067.05
35.00	27.61	3032.49	13.28	3011.30	22.53	3067.05
40.00	27.61	3032.49	13.28	3011.30	22.53	3067.05
45.00	27.61	3032.49	13.28	3011.30	22.53	3067.05
Gas Ava.	**GAP-1**		**GAP-2**		**GAP-3**	
	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	2885.00	10.00	2851.00	10.00	2869.00
20.00	20.00	3028.50	20.00	2939.50	20.00	2986.50
25.00	22.25	3057.50	21.36	2949.90	21.91	3004.00
30.00	22.25	3057.50	21.32	2948.00	21.90	3004.00
35.00	22.25	3057.50	21.32	2948.00	21.93	3004.50
40.00	22.23	3057.50	21.32	2948.00	21.92	3004.50
45.00	22.25	3057.50	21.32	2948.00	21.93	3004.50

Table D.13: Optimum oil production for system 1-2

	System 1-2					
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	5315.78	10.00	5383.63	10.00	5316.92
20.00	20.00	5383.38	14.85	5444.98	20.00	5493.00
25.00	25.00	5403.57	14.85	5444.98	23.55	5502.41
30.00	30.00	5420.91	14.85	5444.98	23.55	5502.41
35.00	30.26	5421.80	14.85	5444.98	23.55	5502.41
40.00	30.26	5421.80	14.85	5444.98	23.55	5502.41
45.00	30.26	5421.80	14.85	5444.98	23.55	5502.41
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	5601.00	10.00	5548.50	10.00	5576.00
20.00	20.00	5685.50	18.78	5566.50	20.00	5630.00
25.00	25.00	5699.50	20.12	5570.50	25.00	5623.50
30.00	30.00	5709.00	19.11	5569.50	23.14	5627.50
35.00	35.00	5718.50	19.11	5569.50	23.13	5627.50
40.00	40.00	5727.50	20.33	5568.50	23.13	5627.50
45.00	41.40	5730.00	20.33	5568.50	23.13	5627.50

Table D.14: Optimum oil production for system 1-3

	System 1-3					
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	6206.67	10.00	6297.40	10.00	6233.77
20.00	20.00	6271.63	14.38	6337.59	20.00	6366.80
25.00	25.00	6290.15	14.38	6337.59	23.86	6374.90
30.00	30.00	6300.37	14.38	6337.59	23.86	6374.90
35.00	31.47	6303.37	14.38	6337.59	23.86	6374.90
40.00	31.47	6303.37	14.38	6337.59	23.86	6374.90
45.00	31.47	6303.37	14.38	6337.59	23.86	6374.90
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	6582.50	10.00	6521.00	10.00	6554.00
20.00	20.00	6666.00	16.31	6541.00	20.00	6604.00
25.00	24.34	6691.00	18.47	6537.50	23.77	6611.50
30.00	24.34	6691.00	18.47	6537.50	23.78	6611.50
35.00	24.34	6691.00	18.47	6537.50	23.77	6611.50
40.00	24.32	6691.00	18.47	6537.50	23.77	6611.50
45.00	24.32	6691.00	18.47	6537.50	23.77	6611.50

Table D.15: Optimum oil production for system 1-4

	System 1-4					
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	7216.10	10.00	7285.47	10.00	7239.67
20.00	20.00	7281.27	13.45	7311.70	20.00	7354.60
25.00	25.00	7294.92	13.45	7311.70	21.81	7356.62
30.00	27.61	7302.05	13.45	7311.70	21.81	7356.62
35.00	27.61	7302.05	13.45	7311.70	21.81	7356.62
40.00	27.61	7302.05	13.45	7311.70	21.81	7356.62
45.00	27.61	7302.05	13.45	7311.70	21.81	7356.62
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	7695.00	10.00	7625.00	10.00	7661.50
20.00	20.00	7778.00	19.30	7634.90	20.00	7710.00
25.00	25.00	7798.50	17.71	7643.00	25.00	7709.50
30.00	28.39	7812.00	17.71	7643.00	19.92	7710.00
35.00	28.22	7811.50	17.71	7643.00	19.92	7710.00
40.00	28.22	7811.50	17.71	7643.00	24.94	7707.50
45.00	28.22	7811.50	17.71	7643.00	23.68	7709.50

Table D.16: Optimum oil production for system 1-5

	System 1-5					
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	9812.91	10.00	9844.01	10.00	9806.29
20.00	20.00	9883.45	18.35	9927.29	20.00	9935.40
25.00	25.00	9897.31	18.35	9927.29	25.00	9952.82
30.00	30.00	9903.38	18.35	9927.29	27.02	9954.22
35.00	35.00	9905.27	18.35	9927.29	27.02	9954.22
40.00	37.46	9906.20	18.35	9927.29	27.02	9954.22
45.00	37.46	9906.20	18.35	9927.29	27.02	9954.22
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	10578.00	10.00	10499.50	10.00	10541.00
20.00	20.00	10655.00	18.66	10508.50	19.41	10583.50
25.00	25.00	10661.50	18.97	10505.70	19.85	10582.00
30.00	30.00	10668.00	18.60	10508.50	19.66	10583.00
35.00	35.00	10674.50	18.60	10508.50	19.66	10583.00
40.00	38.64	10679.00	18.60	10508.50	19.66	10583.00
45.00	38.76	10679.50	18.60	10508.50	19.66	10583.00

D.2.2 Layout well 2 : For different Reservoir Pressure

Table D.17: Optimum oil production for system 2-1

	System 2-1					
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	4380.56	10.00	4258.10	10.00	4107.17
20.00	20.00	5130.09	20.00	5271.62	20.00	5155.45
25.00	25.00	5364.62	25.00	5474.65	25.00	5450.05
30.00	30.00	5487.66	30.00	5580.97	30.00	5653.16
35.00	35.00	5610.70	35.00	5629.42	35.00	5786.96
40.00	40.00	5660.61	40.00	5645.06	40.00	5865.88
45.00	45.00	5702.40	42.20	5646.16	45.00	5899.95
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	8471.00	10.00	7828.10	10.00	7752.80
20.00	20.00	9062.00	20.00	7935.30	20.00	7821.40
25.00	24.61	9223.00	19.86	7939.30	19.86	7820.80
30.00	24.61	9223.00	20.16	7934.90	20.16	7821.50
35.00	24.61	9223.00	20.65	7936.30	20.90	7802.00
40.00	24.61	9223.00	20.00	7935.60	20.44	7818.00
45.00	24.61	9223.00	21.09	7930.30	14.67	7820.80

Table D.18: Optimum oil production for system 2-2

	System 2-2					
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	14043.27	10.00	14287.36	10.00	13756.76
20.00	20.00	15974.24	20.00	16387.99	20.00	15999.50
25.00	25.00	16441.12	25.00	16666.14	25.00	16592.11
30.00	30.00	16645.98	29.72	16728.05	30.00	16974.00
35.00	35.00	16797.57	29.72	16728.05	35.00	17196.22
40.00	40.00	16833.21	29.72	16728.05	40.00	17292.01
45.00	45.00	16868.86	29.72	16728.05	42.07	17300.36
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	19424.50	10.00	17173.50	10.00	18153.00
20.00	20.00	20150.50	20.00	17441.00	20.00	18578.10
25.00	25.00	20338.00	23.27	17522.60	24.90	18709.40
30.00	27.24	20418.50	23.30	17523.70	24.92	18710.10
35.00	27.20	20418.00	23.38	17525.00	24.92	18710.20
40.00	27.23	20418.50	23.31	17523.70	24.94	18710.60
45.00	27.24	20418.50	23.27	17522.50	24.96	18710.50

Table D.19: Optimum oil production for system 2-3

System 2-3						
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	20423.52	10.00	20381.67	10.00	20422.35
20.00	20.00	22149.28	20.00	22263.68	20.00	22060.00
25.00	25.00	22576.90	25.00	22696.14	25.00	22537.59
30.00	30.00	22939.85	30.00	22958.23	30.00	22879.19
35.00	35.00	23093.58	35.00	23111.93	35.00	23117.74
40.00	40.00	23229.95	40.00	23197.19	40.00	23274.70
45.00	43.18	23316.75	45.00	23241.30	45.00	23365.00
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	25765.50	10.00	22494.50	10.00	23871.00
20.00	20.00	26501.50	20.00	22814.70	20.00	24315.60
25.00	25.00	26595.00	19.75	22816.20	25.00	24339.10
30.00	30.00	26685.00	30.00	22816.50	30.00	24419.00
35.00	35.00	26772.50	26.25	22790.80	32.63	24482.00
40.00	35.66	26784.00	29.78	22816.20	32.62	24481.50
45.00	35.67	26784.00	30.24	22816.90	32.53	24479.60

Table D.20: Optimum oil production for system 2-4

System 2-4						
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	27933.28	10.00	27960.59	10.00	28070.02
20.00	20.00	29392.04	20.00	29378.88	20.00	29191.20
25.00	25.00	29803.21	25.00	29810.35	25.00	29555.00
30.00	30.00	30091.52	30.00	30128.74	30.00	29840.38
35.00	35.00	30307.59	35.00	30360.53	35.00	30066.34
40.00	40.00	30471.40	40.00	30522.77	40.00	30245.24
45.00	45.00	30541.71	45.00	30627.13	45.00	30385.70
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	33264.00	10.00	29018.20	10.00	30768.00
20.00	20.00	33854.00	20.00	29273.00	20.00	31179.60
25.00	25.00	34001.50	19.56	29287.50	25.00	31184.00
30.00	30.00	34028.00	22.42	29200.20	26.94	31188.00
35.00	35.00	34054.50	25.67	29132.10	35.00	31192.30
40.00	40.00	34080.00	28.92	29076.70	40.00	31205.50
45.00	45.00	34105.50	32.17	29046.70	41.27	31206.60

Table D.21: Optimum oil production for system 2-5

	System 2-5					
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	41804.19	10.00	41834.09	10.00	41975.11
20.00	20.00	42547.88	20.00	42505.85	20.00	42465.60
25.00	25.00	42766.27	25.00	42739.57	25.00	42634.05
30.00	30.00	42938.46	30.00	42925.60	30.00	42771.89
35.00	35.00	43066.25	35.00	43071.42	35.00	42886.53
40.00	40.00	43169.26	40.00	43181.87	40.00	42982.82
45.00	45.00	43202.62	45.00	43260.25	45.00	43064.10
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	46262.00	10.00	42234.00	10.00	43679.50
20.00	20.00	46575.00	19.30	42262.10	20.00	43881.50
25.00	25.00	46653.50	19.75	42260.00	25.00	43948.10
30.00	30.00	46730.50	23.88	42251.50	29.35	44008.50
35.00	31.12	46747.50	26.25	42247.50	30.63	43978.50
40.00	31.00	46745.50	29.50	42209.50	29.35	44008.50
45.00	31.00	46745.50	27.97	42253.70	29.49	44005.00

D.2.3 Same layout well 3

Table D.22: Optimum value found using different methods of optimisation layout well 3

	Initial Gas injection greater than zero							
	Piecewise		**Alarcon**		**Rashid**		**GAP**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	5166.36	10.00	5239.99	10.00	5044.76	10.00	14394.00
20.00	20.00	6125.34	20.00	6224.31	20.00	6207.00	20.00	15016.00
25.00	25.00	6284.20	25.00	6365.70	25.00	6485.24	25.00	15289.50
30.00	30.00	6413.68	30.00	6410.89	30.00	6642.78	30.00	15544.00
35.00	35.00	6450.08	32.18	6414.07	35.00	6708.85	35.00	15779.50
40.00	40.00	6486.48	32.18	6414.07	36.98	6714.17	40.00	16000.00
45.00	40.87	6492.85	32.18	6414.07	36.98	6714.17	45.00	16209.50

D.2.4 Different layout system 1

Table D.23: Optimum value found using different methods of optimisation system 1

System 1						
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	12305.82	10.00	12307.95	10.00	12240.34
20.00	20.00	13080.14	20.00	13075.22	20.00	12971.25
25.00	25.00	13180.49	25.00	13200.84	25.00	13149.45
30.00	30.00	13229.85	30.00	13248.57	30.00	13256.16
35.00	35.00	13256.06	34.52	13261.98	35.00	13310.34
40.00	37.11	13263.20	34.52	13261.98	39.50	13324.41
45.00	37.11	13263.20	34.52	13261.98	39.50	13324.41
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	14120.50	10.00	13085.90	10.00	13493.30
20.00	20.00	14398.60	20.00	13126.40	20.00	13659.30
25.00	25.00	14482.90	16.54	13166.30	25.00	13661.70
30.00	29.51	14486.90	17.42	13217.40	25.76	13691.30
35.00	33.19	14497.30	17.93	13254.00	19.66	13673.70
40.00	32.91	14496.90	19.41	13239.40	21.48	13676.20
45.00	33.07	14496.40	19.41	13239.40	21.89	13674.00

D.2.5 Different layout system 2

Table D.24: Optimum value found using different methods of optimisation system 2

System 2						
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	6129.43	10.00	6217.80	10.00	6053.42
20.00	20.00	6991.44	20.00	7085.38	20.00	6975.71
25.00	25.00	7172.07	25.00	7215.89	25.00	7210.99
30.00	30.00	7284.59	30.00	7260.73	30.00	7357.16
35.00	35.00	7331.88	32.60	7264.98	35.00	7436.25
40.00	39.69	7364.67	32.60	7264.98	40.00	7462.56
45.00	39.69	7364.67	32.60	7264.98	40.41	7462.71
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	9768.30	10.00	8377.40	10.00	9131.50
20.00	20.00	10378.60	20.00	8628.90	20.00	9402.80
25.00	25.00	10682.80	25.00	8646.40	25.00	9220.60
30.00	30.00	10902.70	30.00	8845.10	30.00	9640.80
35.00	35.00	11102.50	35.00	8914.70	35.00	9863.70
40.00	40.00	11284.80	40.00	9102.90	40.00	9932.80
45.00	45.00	11443.30	44.42	9249.10	45.00	10130.00

D.2.6 Different layout system 3

Table D.25: Optimum value found using different methods of optimisation system 3

System 3						
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	5817.11	10.00	5896.71	10.00	5838.51
20.00	20.00	5892.04	14.57	5940.59	20.00	5976.79
25.00	25.00	5911.31	14.57	5940.59	23.68	5984.58
30.00	30.00	5921.78	14.57	5940.59	23.68	5984.58
35.00	31.54	5923.31	14.57	5940.59	23.68	5984.58
40.00	31.54	5923.31	14.57	5940.59	23.68	5984.58
45.00	31.54	5923.31	14.57	5940.59	23.68	5984.58
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	6147.30	10.00	6091.80	10.00	6121.50
20.00	19.99	6247.10	18.19	6118.20	20.00	6185.50
25.00	25.00	6265.70	20.09	6121.70	24.65	6184.10
30.00	29.90	6273.90	20.09	6121.70	26.48	6171.60
35.00	30.60	6272.80	20.09	6121.70	26.48	6171.60
40.00	31.97	6272.10	20.09	6121.70	26.48	6171.60
45.00	30.96	6273.60	20.09	6121.70	26.48	6171.60

D.2.7 Different layout system 4

Table D.26: Optimum value found using different methods of optimisation system 4

System 4						
	Piecewise		**Alarcon**		**Rashid**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	21926.74	10.00	22003.56	10.00	21916.37
20.00	20.00	23047.98	20.00	23211.13	20.00	23098.72
25.00	25.00	23326.52	25.00	23513.77	25.00	23428.47
30.00	30.00	23553.20	30.00	23712.71	30.00	23663.45
35.00	35.00	23737.29	35.00	23836.92	35.00	23831.69
40.00	40.00	23872.99	40.00	23904.49	40.00	23951.13
45.00	45.00	23941.25	45.00	23931.52	45.00	24033.87
	GAP-1		**GAP-2**		**GAP-3**	
Gas Ava.	Qg	Qo	Qg	Qo	Qg	Qo
MMscf/D	MMscf/D	STB/D	MMscf/D	STB/D	MMscf/D	STB/D
10.00	10.00	26732.50	10.00	23605.70	10.00	24880.90
20.00	20.00	27261.60	20.00	23758.50	20.00	25159.90
25.00	25.00	27368.20	25.00	23623.10	25.00	25176.10
30.00	30.00	27440.00	23.71	23649.30	30.00	25167.10
35.00	32.54	27450.90	21.98	23680.20	33.43	25129.80
40.00	32.63	27453.30	23.52	23631.60	33.10	25136.10
45.00	32.61	27453.30	24.52	23596.60	34.82	25070.20

D.3 Perceptual Error Calculation Value

D.3.1 Same layout well 1:For different Reservoir Pressure

Table D.27: Difference between GAP-1, GAP-2 and GAP-3 with and piecewise method for different system layout 1

Piecewise - GAP 1					
	System				
Gas Ava.	1-1	1-2	1-3	1-4	1-5
10	0.14%	5.09%	5.71%	6.22%	7.23%
20	1.54%	5.31%	5.92%	6.39%	7.24%
25	1.38%	5.19%	5.99%	6.46%	7.17%
30	0.82%	5.05%	5.84%	6.53%	7.17%
35	0.82%	5.19%	5.79%	6.52%	7.21%
40	0.82%	5.34%	5.79%	6.52%	7.24%
45	0.82%	5.38%	5.79%	6.52%	7.24%
Average	**0.91%**	**5.22%**	**5.83%**	**6.45%**	**7.21%**

Piecewise - GAP 2					
	System				
Gas Ava.	1-1	1-2	1-3	1-4	1-5
10	1.34%	4.19%	4.82%	5.36%	6.54%
20	1.45%	3.29%	4.12%	4.63%	5.95%
25	2.21%	3.00%	3.78%	4.55%	5.79%
30	2.87%	2.67%	3.63%	4.46%	5.76%
35	2.87%	2.65%	3.58%	4.46%	5.74%
40	2.87%	2.63%	3.58%	4.46%	5.73%
45	2.87%	2.63%	3.58%	4.46%	5.73%
Average	**2.35%**	**3.01%**	**3.87%**	**4.63%**	**5.89%**
Piecewise - GAP 3					
	System				
Gas Ava.	1-1	1-2	1-3	1-4	1-5
10	0.70%	4.67%	5.30%	5.81%	6.91%
20	0.15%	4.38%	5.03%	5.56%	6.61%
25	0.37%	3.91%	4.86%	5.38%	6.47%
30	0.95%	3.67%	4.71%	5.29%	6.42%
35	0.93%	3.66%	4.66%	5.29%	6.40%
40	0.93%	3.66%	4.66%	5.26%	6.40%
45	0.93%	3.66%	4.66%	5.29%	6.40%
Average	**0.71%**	**3.94%**	**4.84%**	**5.41%**	**6.52%**

Table D.28: Difference between GAP-1,GAP-2 and GAP-3 with and curve fitting using Alaracón equation for different system layout 1

Alaracon et al. - GAP 1					
	System				
Gas Ava.	1-1	1-2	1-3	1-4	1-5
10	3.54%	3.88%	4.33%	5.32%	6.94%
20	0.57%	4.23%	4.93%	6.00%	6.83%
25	1.51%	4.47%	5.28%	6.24%	6.89%
30	1.51%	4.62%	5.28%	6.40%	6.94%
35	1.51%	4.78%	5.28%	6.40%	7.00%
40	1.51%	4.93%	5.28%	6.40%	7.04%
45	1.51%	4.97%	5.28%	6.40%	7.04%
Average	**1.67%**	**4.56%**	**5.10%**	**6.17%**	**6.95%**
Alaracon et al. - GAP 2					
	System				
Gas Ava.	1-1	1-2	1-3	1-4	1-5
10	4.78%	2.97%	3.43%	4.45%	6.24%
20	2.44%	2.18%	3.11%	4.23%	5.53%
25	2.08%	2.25%	3.06%	4.33%	5.51%
30	2.15%	2.24%	3.06%	4.33%	5.53%
35	2.15%	2.24%	3.06%	4.33%	5.53%
40	2.15%	2.22%	3.06%	4.33%	5.53%
45	2.15%	2.22%	3.06%	4.33%	5.53%
Average	**2.56%**	**2.33%**	**3.12%**	**4.34%**	**5.63%**

Alaracon et al. - GAP 3					
	System				
Gas Ava.	1-1	1-2	1-3	1-4	1-5
10	4.12%	3.45%	3.92%	4.91%	6.61%
20	0.83%	3.29%	4.03%	5.17%	6.20%
25	0.24%	3.17%	4.14%	5.16%	6.19%
30	0.24%	3.24%	4.14%	5.17%	6.20%
35	0.23%	3.24%	4.14%	5.17%	6.20%
40	0.23%	3.24%	4.14%	5.14%	6.20%
45	0.23%	3.24%	4.14%	5.16%	6.20%
Average	**0.87%**	**3.27%**	**4.09%**	**5.12%**	**6.25%**

Table D.29: Difference between GAP-1, GAP-2 and GAP-3 with curve fitting Rashid equation for different system layout 1

Rashid et al. - GAP 1					
	System				
Gas Ava.	1-1	1-2	1-3	1-4	1-5
10	1.87%	5.07%	5.30%	5.92%	7.30%
20	1.15%	3.39%	4.49%	5.44%	6.75%
25	0.31%	3.46%	4.72%	5.67%	6.65%
30	0.31%	3.62%	4.72%	5.83%	6.69%
35	0.31%	3.78%	4.72%	5.82%	6.75%
40	0.31%	3.93%	4.72%	5.82%	6.79%
45	0.31%	3.97%	4.72%	5.82%	6.79%
Average	**0.65%**	**3.89%**	**4.77%**	**5.76%**	**6.82%**
Rashid et al. - GAP 2					
	System				
Gas Ava.	1-1	1-2	1-3	1-4	1-5
10	3.08%	4.17%	4.40%	5.05%	6.60%
20	4.21%	1.32%	2.66%	3.67%	5.45%
25	3.97%	1.22%	2.49%	3.75%	5.26%
30	4.04%	1.20%	2.49%	3.75%	5.27%
35	4.04%	1.20%	2.49%	3.75%	5.27%
40	4.04%	1.19%	2.49%	3.75%	5.27%
45	4.04%	1.19%	2.49%	3.75%	5.27%
Average	**3.92%**	**1.64%**	**2.79%**	**3.92%**	**5.49%**
Rashid et al. - GAP 3					
	System				
Gas Ava.	1-1	1-2	1-3	1-4	1-5
10	2.44%	4.65%	4.89%	5.51%	6.97%
20	2.57%	2.43%	3.59%	4.61%	6.12%
25	2.10%	2.15%	3.58%	4.58%	5.95%
30	2.10%	2.22%	3.58%	4.58%	5.94%
35	2.08%	2.22%	3.58%	4.58%	5.94%
40	2.08%	2.22%	3.58%	4.55%	5.94%
45	2.08%	2.22%	3.58%	4.58%	5.94%
Average	**2.21%**	**2.59%**	**3.77%**	**4.71%**	**6.11%**

D.3.2 Same layout well 2: For different Reservoir Pressure

Table D.30: Difference between GAP-1, GAP-2 and GAP-3 with piecewise method for different system layout well 2

Piecewise - GAP 1					
Gas Ava.	System				
	2-1	2-2	2-3	2-4	2-5
10	48.29%	27.70%	20.73%	16.03%	9.64%
20	43.39%	20.73%	16.42%	13.18%	8.65%
25	41.83%	19.16%	15.11%	12.35%	8.33%
30	40.50%	18.48%	14.03%	11.57%	8.11%
35	39.17%	17.73%	13.74%	11.00%	7.87%
40	38.63%	17.56%	13.27%	10.59%	7.65%
45	38.17%	17.38%	12.95%	10.45%	7.58%
Average	**41.42%**	**19.82%**	**15.18%**	**12.17%**	**8.26%**
Piecewise - GAP 2					
Gas Ava.	System				
	2-1	2-2	2-3	2-4	2-5
10	44.04%	18.23%	9.21%	3.74%	1.02%
20	35.35%	8.41%	2.92%	0.41%	0.68%
25	32.43%	6.17%	1.05%	1.76%	1.20%
30	30.84%	5.01%	0.54%	3.05%	1.63%
35	29.30%	4.15%	1.33%	4.04%	1.94%
40	28.67%	3.94%	1.81%	4.80%	2.27%
45	28.09%	3.73%	2.19%	5.15%	2.25%
Average	**32.68%**	**7.09%**	**2.72%**	**3.28%**	**1.57%**
Piecewise - GAP 3					
Gas Ava.	System				
	2-1	2-2	2-3	2-4	2-5
10	43.50%	22.64%	14.44%	6.63%	4.29%
20	34.41%	14.02%	8.91%	5.73%	3.04%
25	31.41%	12.12%	7.24%	4.43%	2.69%
30	29.84%	11.03%	6.06%	3.52%	2.43%
35	28.09%	10.22%	5.67%	2.84%	2.07%
40	27.60%	10.03%	5.11%	2.35%	1.91%
45	27.09%	9.84%	4.75%	2.13%	1.82%
Average	**31.70%**	**12.84%**	**7.45%**	**3.95%**	**2.61%**

Table D.31: Difference between GAP-1, GAP-2 and GAP-3 with curve fitting using Alaracón equation for different system layout well 2

Alaracon et al. - GAP 1					
Gas Ava.	System				
	2-1	2-2	2-3	2-4	2-5
10	49.73%	26.45%	20.90%	15.94%	9.57%
20	41.83%	18.67%	15.99%	13.22%	8.74%
25	40.64%	18.05%	14.66%	12.33%	8.39%
30	39.49%	18.07%	13.97%	11.46%	8.14%
35	38.96%	18.07%	13.67%	10.85%	7.86%
40	38.79%	18.07%	13.39%	10.44%	7.62%
45	38.78%	18.07%	13.23%	10.20%	7.46%
Average	**41.18%**	**19.35%**	**15.11%**	**12.06%**	**8.25%**
Alaracon et al. - GAP 2					
Gas Ava.	System				
	2-1	2-2	2-3	2-4	2-5
10	45.60%	16.81%	9.39%	3.64%	0.95%
20	33.57%	6.04%	2.42%	0.36%	0.58%
25	31.04%	4.89%	0.53%	1.79%	1.13%
30	29.67%	4.54%	0.62%	3.18%	1.60%
35	29.07%	4.55%	1.41%	4.22%	1.95%
40	28.86%	4.54%	1.67%	4.97%	2.30%
45	28.80%	4.53%	1.86%	5.44%	2.38%
Average	**32.37%**	**6.56%**	**2.56%**	**3.37%**	**1.56%**
Alaracon et al. - GAP 3					
Gas Ava.	System				
	2-1	2-2	2-3	2-4	2-5
10	49.73%	26.45%	20.90%	15.94%	9.57%
20	32.60%	11.79%	8.44%	5.78%	3.13%
25	30.00%	10.92%	6.75%	4.40%	2.75%
30	28.65%	10.59%	5.98%	3.40%	2.46%
35	27.85%	10.59%	5.60%	2.67%	2.06%
40	27.79%	10.60%	5.25%	2.19%	1.88%
45	27.81%	10.60%	5.06%	1.86%	1.69%
Average	**32.06%**	**13.08%**	**8.28%**	**5.18%**	**3.36%**

Table D.32: Difference between GAP-1, GAP-2 and GAP-3 with curve fitting using Rashid equation for different system layout well 2

Rashid et al. - GAP 1					
	System				
Gas Ava.	2-1	2-2	2-3	2-4	2-5
10	51.51%	29.18%	20.74%	15.61%	9.27%
20	43.11%	20.60%	16.76%	13.77%	8.82%
25	40.91%	18.42%	15.26%	13.08%	8.62%
30	38.71%	16.87%	14.26%	12.31%	8.47%
35	37.26%	15.78%	13.65%	11.71%	8.26%
40	36.40%	15.31%	13.10%	11.25%	8.05%
45	36.03%	15.27%	12.77%	10.91%	7.88%
Average	**40.56%**	**18.78%**	**15.22%**	**12.66%**	**8.48%**

Rashid et al. - GAP 2					
	System				
Gas Ava.	2-1	2-2	2-3	2-4	2-5
10	47.53%	19.90%	9.21%	3.27%	0.61%
20	35.03%	8.27%	3.31%	0.28%	0.48%
25	31.35%	5.31%	1.22%	0.91%	0.89%
30	28.76%	3.14%	0.27%	2.19%	1.23%
35	27.08%	1.88%	1.43%	3.21%	1.51%
40	26.08%	1.32%	2.01%	4.02%	1.83%
45	25.60%	1.27%	2.40%	4.61%	1.92%
Average	**31.63%**	**5.87%**	**2.84%**	**2.64%**	**1.21%**

Rashid et al. - GAP 3					
	System				
Gas Ava.	2-1	2-2	2-3	2-4	2-5
10	47.02%	24.22%	14.45%	6.17%	3.90%
20	34.09%	13.88%	9.28%	6.38%	3.23%
25	30.31%	11.32%	7.40%	5.22%	2.99%
30	27.72%	9.28%	6.31%	4.32%	2.81%
35	25.83%	8.09%	5.57%	3.61%	2.48%
40	24.97%	7.58%	4.93%	3.08%	2.33%
45	24.56%	7.54%	4.55%	2.63%	2.14%
Average	**30.64%**	**11.70%**	**7.50%**	**4.49%**	**2.84%**

D.3.3 Same layout system well 3

Table D.33: Difference between GAP and the excel method

Gas Ava.	Piecewise-Lin	Alaracon et al.	Rashid et al.
10	64.11%	63.60%	64.95%
20	59.21%	58.55%	58.66%
25	58.90%	58.37%	57.58%
30	58.74%	58.76%	57.26%
35	59.12%	59.35%	57.48%
40	59.46%	59.91%	58.04%
45	59.94%	60.43%	58.58%
Average	**59.93%**	**59.85%**	**58.94%**

D.3.4 Different layout system 1

Table D.34: Difference between GAP and the excel method system 1

	Piecewise-Linear		
Gas Ava.	**GAP-1**	**GAP - 2**	**GAP - 3**
10	12.85%	5.96%	8.80%
20	9.16%	0.35%	4.24%
25	8.99%	0.11%	3.52%
30	8.68%	0.09%	3.37%
35	8.56%	0.02%	3.05%
40	8.51%	0.18%	3.02%
45	8.51%	0.18%	3.00%
Average	**9.32%**	**0.98%**	**4.14%**
	Alaracon et al.		
Gas Ava.	**GAP-1**	**GAP - 2**	**GAP - 3**
10	12.84%	5.94%	8.78%
20	9.19%	0.39%	4.28%
25	8.85%	0.26%	3.37%
30	8.55%	0.24%	3.23%
35	8.52%	0.06%	3.01%
40	8.52%	0.17%	3.03%
45	8.52%	0.17%	3.01%
Average	**9.28%**	**1.03%**	**4.10%**
	Rashid et al.		
Gas Ava.	**GAP-1**	**GAP - 2**	GAP - 3
10	13.32%	6.46%	9.29%
20	9.91%	1.18%	5.04%
25	9.21%	0.13%	3.75%
30	8.50%	0.29%	3.18%
35	8.19%	0.43%	2.66%
40	8.09%	0.64%	2.57%
45	8.08%	0.64%	2.56%
Average	**9.33%**	**1.40%**	**4.15%**

D.3.5 Different layout system 2

Table D.35: Difference between GAP and the excel method system 2

Gas Ava.	GAP-1	GAP - 2	GAP - 3
	Piecewise-Linear		
Gas Ava.	**GAP-1**	**GAP - 2**	**GAP - 3**
10	37.25%	26.83%	32.88%
20	32.64%	18.98%	25.65%
25	32.86%	17.05%	22.22%
30	33.19%	17.64%	24.44%
35	33.96%	17.76%	25.67%
40	34.74%	19.10%	25.86%
45	35.64%	20.37%	27.30%
Average	**34.33%**	**19.68%**	**26.29%**
	Alaracon et al.		
Gas Ava.	**GAP-1**	**GAP - 2**	**GAP - 3**
10	36.35%	25.78%	31.91%
20	31.73%	17.89%	24.65%
25	32.45%	16.54%	21.74%
30	33.40%	17.91%	24.69%
35	34.56%	18.51%	26.35%
40	35.62%	20.19%	26.86%
45	36.51%	21.45%	28.28%
Average	**34.38%**	**19.75%**	**26.35%**
	Rashid et al.		
Gas Ava.	**GAP-1**	**GAP - 2**	GAP - 3
10	38.03%	27.74%	33.71%
20	32.79%	19.16%	25.81%
25	32.50%	16.60%	21.79%
30	32.52%	16.82%	23.69%
35	33.02%	16.58%	24.61%
40	33.87%	18.02%	24.87%
45	34.79%	19.31%	26.33%
Average	**33.93%**	**19.18%**	**25.83%**

D.3.6 Different layout system 3

Table D.36: Difference between GAP and the excel method system 3

	Piecewise-Linear		
Gas Ava.	**GAP-1**	**GAP - 2**	**GAP - 3**
10	5.37%	4.51%	4.97%
20	5.68%	3.70%	4.74%
25	5.66%	3.44%	4.41%
30	5.61%	3.27%	4.05%
35	5.57%	3.24%	4.02%
40	5.56%	3.24%	4.02%
45	5.58%	3.24%	4.02%
Average	**5.58%**	**3.52%**	**4.32%**

	Alaracon et al.		
Gas Ava.	**GAP-1**	**GAP - 2**	**GAP - 3**
10	4.08%	3.20%	3.67%
20	4.91%	2.90%	3.96%
25	5.19%	2.96%	3.94%
30	5.31%	2.96%	3.74%
35	5.30%	2.96%	3.74%
40	5.29%	2.96%	3.74%
45	5.31%	2.96%	3.74%
Average	**5.05%**	**2.99%**	**3.79%**
	Rashid et al.		
Gas Ava.	**GAP-1**	**GAP - 2**	GAP - 3
10	5.02%	4.16%	4.62%
20	4.33%	2.31%	3.37%
25	4.49%	2.24%	3.23%
30	4.61%	2.24%	3.03%
35	4.59%	2.24%	3.03%
40	4.58%	2.24%	3.03%
45	4.61%	2.24%	3.03%
Average	**4.60%**	**2.52%**	**3.33%**

D.3.7 Different layout system 4

Table D.37: Difference between GAP and the excel method system 4

	Piecewise-Linear		
Gas Ava.	**GAP-1**	**GAP - 2**	**GAP - 3**
10	17.95%	7.08%	11.84%
20	15.19%	2.69%	8.11%
25	14.35%	0.77%	6.89%
30	13.80%	0.02%	6.01%
35	13.31%	0.49%	5.30%
40	12.95%	1.13%	4.93%
45	12.79%	1.47%	4.49%
Average	**14.33%**	**1.95%**	**6.80%**
	Alaracon et al.		
Gas Ava.	**GAP-1**	**GAP - 2**	**GAP - 3**
10	17.69%	6.79%	11.56%
20	14.86%	2.30%	7.75%
25	14.08%	0.46%	6.60%
30	13.58%	0.27%	5.78%
35	13.17%	0.66%	5.14%
40	12.93%	1.15%	4.90%
45	12.83%	1.41%	4.55%
Average	**14.16%**	**1.86%**	**6.61%**
	Rashid et al.		
Gas Ava.	**GAP-1**	**GAP - 2**	GAP - 3
10	18.02%	7.16%	11.91%
20	15.27%	2.78%	8.19%
25	14.40%	0.82%	6.94%
30	13.76%	0.06%	5.97%
35	13.18%	0.64%	5.17%
40	12.76%	1.35%	4.71%
45	12.46%	1.85%	4.13%
Average	**14.26%**	**2.09%**	**6.72%**