ASSESSMENT OF PRODUCTION STRATEGIES
OF A GAS CONDENSATE FIELD
USING A BLACK OIL SIMULATOR:
A CASE STUDY

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

BURAK PARLAKTUNA

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF MASTER OF SCIENCE
IN
PETROLEUM AND NATURAL GAS ENGINEERING

SEPTEMBER 2015

Approval of the thesis:

ASSESSMENT OF PRODUCTION STRATEGIES OF A GAS CONDENSATE FIELD USING A BLACK OIL SIMULATOR: A CASE STUDY

submitted by **BURAK PARLAKTUNA** in partial fulfillment of the requirements for the degree of **Masters of Science in Petroleum and Natural Gas Engineering Department**, **Middle East Technical University** by,

Prof. Dr. Gülbin Dural Ünver ________
Dean, Graduate School of **Natural and Applied Sciences**

Prof. Dr. Mustafa Kök ________
Head of Department, **Petroleum and Natural Gas Engineering**

Assist. Prof. Dr. Çağlar Sınayuç ________
Supervisor, **Petroleum and Natural Gas Engineering Dept., METU**

Examining Committee Members:

Prof. Dr. Mustafa Kök ________________
Petroleum and Natural Gas Engineering Dept., METU

Assist. Prof. Dr. Çağlar Sınayuç ________________
Petroleum and Natural Gas Engineering Dept., METU

Assist. Prof. Dr. İsmail Durgut ________________
Petroleum and Natural Gas Engineering Dept., METU

Assoc. Prof. Dr. Uğur Murat Leloğlu ________________
Geodetic and Geographical Information Technologies, METU

Assist. Prof. Dr. Emre Artun ________________
Petroleum and Natural Gas Engineering Dept., METU NCC

Date: 02.09.2015

I hereby declare that all information in this document has been obtained and presented in accordance with academic rules and ethical conduct. I also declare that, as required by these rules and conduct, I have fully cited and referenced all material and results that are not original to this work.

Name, Last Name: *Burak PARLAKTUNA*

Signature:

ABSTRACT

ASSESSMENT OF PRODUCTION STRATEGIES OF A GAS CONDENSATE FIELD USING A BLACK OIL SIMULATOR: A CASE STUDY

Parlaktuna, Burak
M. S, Department of Petroleum and Natural Gas Engineering
Supervisor: Assist. Dr. Çağlar Sınayuç

September 2015, 96 pages

Condensates are low-density liquids that are produced along with the gas phase from wet gas or gas-condensate reservoirs. Availability of these liquids makes gas-condensate reservoirs more profitable than the other gas reservoirs since condensates are gasoline like fluids with API gravities more than 45°. Although the condensate production is profitable, the management of gas-condensate reservoirs is challenging. Due to their nature, condensates condense and separate from the gas if the pressure drops below the dew point pressure. The condensation causes an increase in the amount of liquid drop-out especially around the wellbores where the maximum pressure drop occurs. The condensates around the wellbores decreases or even blocks the flow of gas into the wells due relative permeability effects. Therefore it is required to prevent condensation in the reservoir which can be done by keeping the reservoir pressure high. On the other hand, bottom hole well pressures should be low enough to have a good production rate.

This dissertation aims to assess different production and injection strategies and find out the optimal one by constructing static and dynamic reservoir models and simulate the production strategies for 50 more years in addition to the 45 years of production history of a South Caspian Basin field. The starting point of this study is to construct a static model based on an existing reservoir which consist of three blocks with eleven producing layers. The required fluid model is obtained using available fluid properties by the help of a compositional PVT equation of state software prior the preparation of dynamic or flow model. The production history of the field is used to construct a base for the simulations. The volumetric calculations are compared with the available data. Different production scenarios are applied including production at different rates, injection of water and gas separately and simultaneously as well. It was observed that keeping the pressure high with water injection in the reservoir but using the driving force of gas at the same time leads the minimum amount of liquid drop-out in the reservoir.

Keywords: Gas condensate, Modelling, Simulation, Reservoir Management

ÖZ

SİMÜLATOR KULLANARAK BİR GAZ KONDANSAT SAHASININ ÜRETİM STRATEJİLERİNİN DEĞERLENDİRİLMESİ: SAHA ÇALIŞMASI

Parlaktuna, Burak
Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği
Tez Yöneticisi: Y. Doç. Dr. Çağlar Sınayuç

Eylül 2015, 96 sayfa

Kondansatlar düşük yoğunluktaki akışkanlar olup gaz ile birlikte Gaz kondansat sahalarından üretilmektedir. Bu rezervuarlar diğer gaz sahalarına göre ekonomik anlamda daha verimlidir çünkü kondansatlar genellikle API gravitesi 45°'den yüksek, benzinimsi bir akışkandır. Ama maddi açıdan verimli olan bu sahaların işletilmesi diğer gaz rezervuarlarına göre daha zordur. Bunun başlıca sebebi ise kondansatların, rezervuar basıncı çiğlenme basıncının altına düştüğü anda hal değiştirmesi ve gazdan ayrışmasından ileri gelmektedir. Basınç düşümü üretimin olduğu kuyuların çevresinde çok yüksektir ve kuyu çevresinde açığa çıkan sıvı miktarı yoğunlaşmanın çok olmasından dolayı fazladır. Kuyu çevresinde oluşan sıvı haldeki kondansatlar rölatif geçirgenlik değerlerine göre, gazın kuyuya doğru akmasını azaltabilir hatta engelleyebilir. Bunu engellemenin başlıca yolu rezervuarın basıncını çiğlenme basıncından yüksek tutmaktır. Fakat kuyu dibi üretim basınçları ise, gaz fazının en uygun seviyede üretilmesini sağlamak amacıyla düşük tutulmalıdır.

Bu tez çalışmasının amacı, statik ve dinamik rezervuar modellemesi yapılarak değişik üretim stratejilerinin, hali hazırda 45 yıllık üretim geçmişine sahip olan bir rezervuara 50 yıl daha simule edilmesi ile değerlendirmektir. Bu tez çalışmasının başlangıç noktası

Güney Hazar Baseninde yer alan ve üç ayrı blok ve on bir farklı üretim seviyesinden oluşmakta olan sahanın statik rezervuar modelinin kurulmasıdır. Çalışma için gerekli olan akışkan modeli, hali hazırda bilinen akışkan özellikleri temel alınarak kompozisyonel PVT yazılımının yardımlarıyla hazırlanmıştır. Bu akışkan modeli, statik rezervuar modeli ile birleştirilerek dinamik rezervuar modelini oluşturacaktır. Oluşturulan dinamik modeldeki sahanın geçmiş üretim verileri, üretim stratejileri için temel modeli yerine geçmektedir. Bu çalışmada değişik değerlerde üretim yapılması, su ve gaz geri basımı hem ayrı ayrı hem de birlikte yapılması değişik üretim stratejileri olarak kurulmuştur. Yapılan incelemelerde gaz ve suyun aynı anda rezervuara geri basılması rezervuarın basıncını yükselttiği ve rezervuarda oluşan sıvı yoğunlaşmasını azalttığı gözlemlenmiştir.

Anahtar Kelimeler: Gaz Kondansat, Modelleme, Simulasyon, Rezervuar Yönetimi

ACKNOWLEDGEMENTS

Firstly, I would like to thank to my supervisor Dr. Çağlar Sinayuç for his guidance, patience and valuable comments. Without your support I could not finish this thesis.

Secondly, I owe my thanks to Dr. Fevzi Gümrah for the topic and data.

I am deeply grateful and thankful to my parents they were with me every step that I take and they are the ones that bare my moods.

My love Merve Turanlı, you are best thing that happens to me in my whole life. You are my focus charm that keep me in the right track in both this thesis and life. Thank you for everything.

Group Davuk, I cannot find the proper words to express my feeling towards you. But I guess brothers and sisters should be sufficient and the most meaningful ones. I am thankful for every moment we share.

My high school classmates, I love you all.

Tuğçe, Göker, Gizem and Betül, thank you all for your friendship, advices and guidance. Also Şükrü thank you for being my walking academic paper library without your papers I will be devastated in the deep sea of academic reading.

Yağmur, Ankara seems to be quieter now. I miss our lunch sessions.

Nuri, Serkan, Onursal and my bros for life (Kemal, Onur, Uğur and Sarp) thanks for the on call morale boosts and dinners. After this thesis finish we need to prepare a dinner and celebrate it.

Lastly, to all of my friends and colleagues that support me throughout this thesis process I thank you all for everything we share.

I am only human…

TABLE OF CONTENTS

LIST OF FIGURES

FIGURES

LIST OF TABLES

TABLES

CHAPTER 1

INTRODUCTION

Condensate is referred to, water-white colored liquid which somewhat similar to the gasoline and it evolves by condensing from produced gas at low pressure conditions. It differentiates from the crude oil due to absence of heavier components. Condensates mostly consist of gasoline and have API gravity more than 50°. The term ‘gas condensate’ expresses condensate which is associated with gas (Thornton, 1946).

Gas condensate reservoir management is one of the challenging subjects that a petroleum engineers can face. From drilling phase to production of the hydrocarbons from the reservoir, that is, in every aspect, gas condensate reservoirs need high attention. This challenges are caused mainly by the special properties of the gas found in gas condensate reservoirs. The pressure decreases due to the production of the gas causes liquid drop-out in the reservoir. Although the evolved liquid which is known as condensate is precious, because of the relative permeability properties of the fluids, the production of the gas is decreased by the formation of liquid block around wellbores.

A slight difference in reservoir pressure can cause liquid drop-out in the reservoir and this leads to loss of precious condensate and also it can also decrease the gas production by forming liquid blockage around wellbore. Therefore engineers working in the field must have an eye on the data at hand.

Simulation of such reservoirs is not so different. Reservoir engineers must gather all available data from the field and search it thoroughly and find the best way to interpret the data. The main challenge for the gas condensate reservoir simulation is to understand the reservoir fluid properties. Since the condensates are in gaseous state in reservoir condition and they condense in low pressure temperature regions such as at separator conditions, the collected fluid sample from the separator may lead erroneous results. In order to overcome this errors, fluid sampling must be conducted from the reservoir section. Good knowledge in Pressure Volume Temperature (PVT) properties of a reservoir fluid is the key parameter to successfully generate a good reservoir model. PVT properties of the reservoir fluids such as; viscosity, compressibility, fluid formation volume factor can be the answer to many questions;

- What is the volumetric extension of this reserve?
- How much of this reserve is producible?
- Does any other types of material other than hydrocarbons contained in the fluid?
- What will be the optimal separator condition?

Having this knowledge along with a well-constructed static reservoir model, dynamic reservoir modelling can be done relatively easily. Static reservoir model contains geological information about the reservoir. Main inputs for static model are seismic surveys of the field, strati graphical logs of drilled wells, petro physical properties from core analysis and well logging and surface geological knowledge of the field. All these data are used to model the initial reservoir rock properties and reservoir statistics. Production data and fluid property data are not necessary during this phase, therefore the geological model of an area sometimes called the static model. On the other hand dynamic reservoir model (fluid model) mainly focuses on the movement of reservoir fluids and changes in reservoir parameters in time. Dynamic fluid model is the next step of a modelling study because it is the combination of the static model and reservoir fluid property model.

The solution of dynamic fluid models requires a simulation software due to high number of calculations necessary to conduct. Mainly a simulation software is divided into two groups in terms of fluid property input. First one is called black oil simulators which only needs some PVT properties of the reservoir fluid with respect to pressure or temperature to calculate the necessary parameters but does not consider the change in composition of the reservoir fluid with changes in pressure, temperature and time. On the other hand second type of simulation software focuses on changes in composition of the reservoir fluid, which is called as compositional simulators. Compositional simulators focus on calculation of the composition of the fluids found in gas and liquid phases for each pressure or time step of a reservoir and give much more detailed results comparing to the black oil simulators. However, compositional simulators are so complex than the black oil simulators that they will lead longer times for a run to finalize. In this thesis Schlumberger's ECLIPSE E100 Black Oil Simulator is used.

Steps of the guideline for this thesis work are as follows;

- Literature survey
- Data gathering and evaluation
- Constructing the geological model
- Verifying geological model by volumetric calculations
- Constructing fluid model
- Verifying fluid model by history matching
- Production forecasting
- Assessing new production strategies

The steps defined above are applied to an existing gas condensate field. The focus area of the simulation study is the sixth layer of the second block of a gas-condensate reservoir found in South Caspian Basin which consists of 3 blocks and 11 producing layers. The field has been in production for nearly 45 years. After so many years of production, due to the pressure decline, gas condensate formations occurred around wellbores which caused most of the producing wells were abandoned. This study aims to understand the reason behind the condensate drop-out and suggests new production strategies to overcome the loss of economically valuable condensates. Suggested production strategies in this field aiming to produce as much as precious condensate possible together with the gas are given below:

- High pressure drop to increase the gas rate,
- Keeping gas production rates as low as possible to maintain the pressure decrease in the reservoir,

- Injection of water, gas or both to increase the overall reservoir pressure

CHAPTER 2

LITERATURE REVIEW

2.1. Geology

Gas condensate reservoirs are similar to gas reservoirs however the gas found in the reservoir can store liquid in it at the reservoir pressure and temperature conditions. These type of gas can is also called “wet-gas”. The field that this study is based on is located at the South Caspian Basin.

The Caspian region and also the Caspian Sea is one of the World’s richest places in terms of petroleum products behind Middle East. In an editorial paper (Djevanshir and Mansoori, 2000) it is stated that the Caspian Sea has proven reserves of 18 – 35 billion barrels of oil and 236 – 337 trillion cubic feet of gas.

Due to numerous number of countries surrounding the Caspian Sea, both nomenclature and also sharing of the reservoirs are debatable. However the South Caspian Basin is surrounded only three countries, namely, Azerbaijan, Iran and Turkmenistan. In their book Buryakovsky et al. (2001) divide the oil and gas bearing reservoir into five main groups,

1. Western portion of Apsheron – Pre – Balkhan Anticlinal Trend
2. South Aspheron Offshore Zone
3. Baku Archipelago
4. Eastern portion of Apsheron – Pre – Balkhan Anticlinal Trend

5. Chikishlyar – Okarem Zone

Where the first three are in the Azerbaijan portion and the last two are located in Turkmenistan portion (Figure 1).

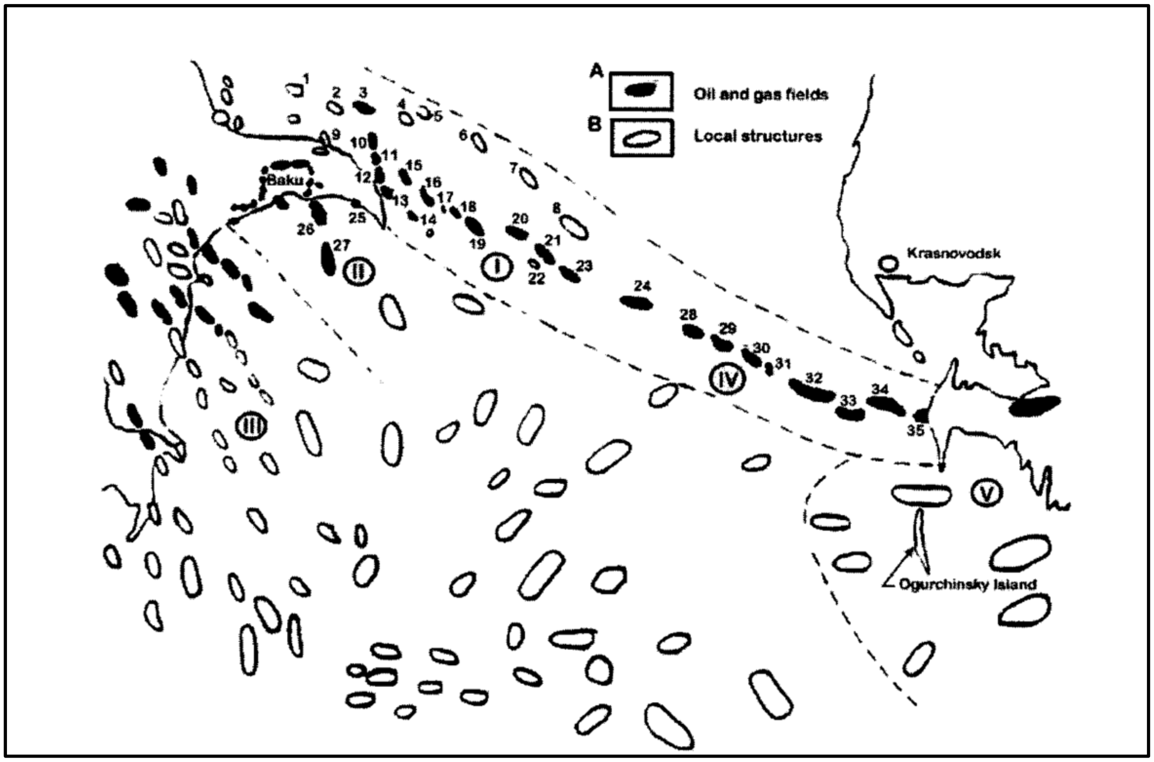

Figure 1. Oil and Gas bearing Reservoirs of South Caspian Sea (Buryakovsky et al., 2001)

Drilling and production of these fields began intensely in the year 1949. According to Buryakovsky et al. (2001), 12 MMt oil and 11 Bm^3 gas were produced and these numbers correspond to the half of the recoverable reserves. All fields shown in Figure 1 are multilayered. Least layered one has 3 layers and it reaches up to 30 layers. The field that is investigated in this thesis have 11 producing layers.

2.2. Modelling

Schlumberger’s PETREL, PVTi, ECLIPSE and FloViz softwares were used in this thesis in order to understand and simulate the conditions of the reservoir.

2.2.1. Geological Model

Schlumberger’s PETREL software was used to create the geological or static reservoir model. According to Zakrevsky (2011), constructing a static model which is consisted with geological knowledge is a fundamental step towards reservoir characterization and performance forecasting. 3D static reservoir models are generally used for; reserve estimation, targeting new well locations, uncertainty and risk analysis, well path design and control, establish a base for production forecasting and cost estimation by paired with dynamic reservoir model simulators.

2.2.2. Fluid Property Model

According to Ahmed (1989) phase behavior for gas condensate reservoirs can be examined in to two parts, retrograde and near critical. In retrograde gas condensate reservoirs, the reservoir temperature is lies anywhere between the critical temperature and the cricondenterm. In this type of reservoirs gas – oil ratios are changing from 8000 – 70000 scf/STB and API gravity for condensates is above 50°. As can be understand by its name in near critical gas condensate reservoirs, the reservoir temperature is at near critical temperature. In this type of reservoir the liquid volume will increase rapidly after pressure drops below the dew point pressure. The reason for this all the quality lines for the phase behavior converges at the critical point. In Figures 2 and 3 typical gas condensate reservoir phase diagrams and liquid percentage vs. pressure diagrams can be seen.

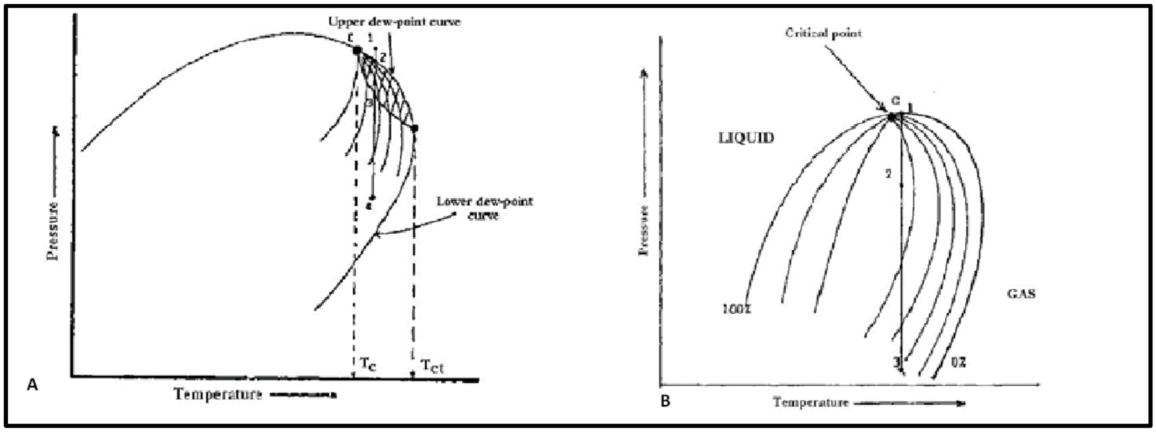

Figure 2. Typical Gas condensate reservoir phase diagrams (A: Retrograde, B: Near Critical, Ahmed, 1989)

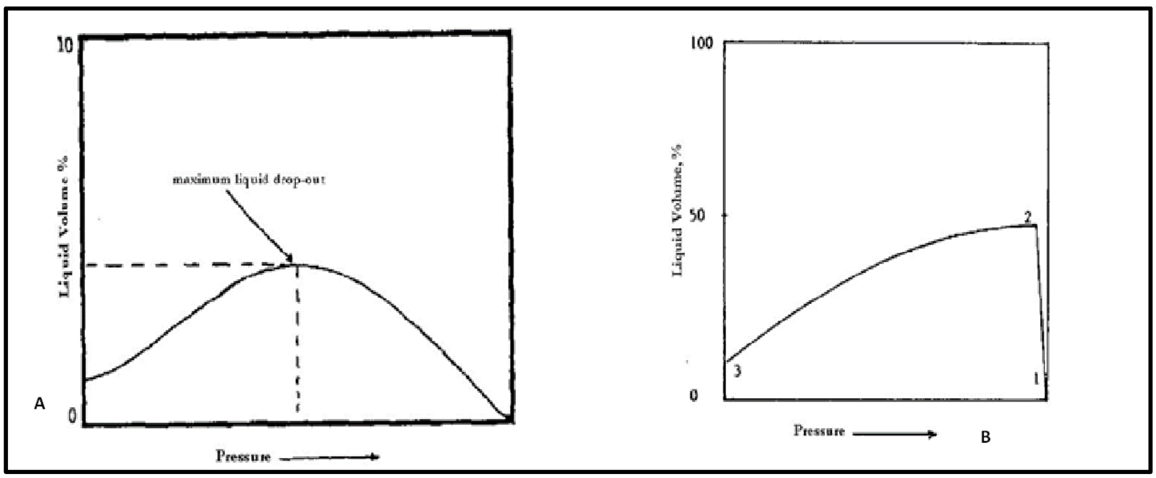

Figure 3. Liquid Content vs Pressure graphs for Gas condensate reservoir (A: Retrograde, B: Near Critical, Ahmed, 1989)

The PVTi software was used to define fluid properties of the reservoir by constructing the PVT tables of all phases in the reservoir along with the depth variated tables such as gas solubility (R_S) versus depth (RSVD) and vaporized oil to gas ratio (R_V) versus depth (RVVD) by using the fluid composition and some basic fluid characterization data such as density, molecular weight and specific gravity of the components. These data coupled with static reservoir model is used for the solution of the dynamic reservoir model.

In order to construct these PVT tables and phase diagrams PVTi software needs some laboratory experiment data. In this thesis Differential Liberation (DL) and Constant Volume Depletion (CVD) experiments were used. According to Ahmed (2010), Differential Liberation experiments are conducted by liberating the solution gas of an oil sample in order to find the amount of gas in the solution as a function of pressure, composition of liberated gas, gas compressibility factor, and specific gravity of gas and density of the remaining oil as a function of pressure. Although it is known that the field is a gas condensate field, differential liberation experiment was used because in some parts of the reservoir, solution gas bearing live oil is present. Ahmed (2010) also states that for a gas condensate reservoir Constant Volume Depletion (CVD) experiment should be conducted. CVD test is mainly used for simulation of gas depletion performance. CVD generally results with a known composition at a certain pressure, however in this thesis CVD data are given to the software as a gas density versus pressure table due to lack of data and it is thought that density could give a clue about the gas composition.

For phase diagrams different Equation-of-State models can be chosen in PVTi software. The software offers seven different EOS models:

- 2- Parameter Peng-Robinson (PR)
- 2- Parameter Soave-Redlich-Kwong (SRK)
- Redlich-Kwong (RK)
- Zudkevitch-Joffe (ZJ)
- 3- Parameter Peng-Robinson (PR3)
- 3- Parameter Soave-Redlich-Kwong (SRK3)
- Schmidt-Wenzel (SW)

In this thesis, SRK3 was used as EOS. It was the best model to be worked with the data at hand. The SRK3 is given in the following Equation 1 (Soave, 1972).

$$\boldsymbol{P = \frac{\bar{R}T}{\bar{v}-b} - \frac{\alpha a}{\bar{v}(\bar{v}+b)}} \qquad \textbf{(1)}$$

Where

$$a = 0.42747 \times \frac{(\bar{R}T_c)^2}{P_c}$$

$$b = 0.08664 \times \frac{\bar{R}T_c}{P_c}$$

$\alpha = \left[1 + m \times \left(1 - \sqrt{T_R}\right)\right]^2$

$m = 0.48508 + 1.5517\omega - 0.1561\omega^2$

T_c: Critical Temperature

P_c: Critical Pressure

T_R: Reduced Temperature

ω: Pitzer Accentric Factor

For a given hydrocarbon fluid composition, lumped hydrocarbon components heavier than heptanes (C7+) are main component for characterization. Some property estimation methods are available in the literature and in this thesis Riazi and Daubert (1980) correlation is used to find out specific gravity of the C7+ components. Although some other correlation and characterization formulae exist offers the best correlation according to data available at hand. The correlation is used to derive the Equation 2 (Whitson & Brulé, 2000).

$$\boldsymbol{K_w = 4.5579 M^{0.15178} \gamma^{-0.84573}} \quad \textbf{(2)}$$

Where;

K_w = Watson Factor

M = Molecular Weight

γ = Specific Gravity

R_V is a crucial variable in order to define a condensate system. Spivak and Dixon (1973) denoted R_V as r_s and called it “Liquid content”. R_V is used in condensate simulations to find out the amount of condensate will be produced for a certain gas production rate as the R_S term is used in black-oil simulations. In Schlumberger’s ECLIPSE Manual R_V is defined as “Vaporized oil-gas ratio” and its units are Sm^3/Sm^3 for metric system stb/Mscf for field system.

2.2.3. Dynamic Model and Simulation

Niri M.E. (2015) states that dynamic reservoir model is used to identify reservoir rock and fluid behavior over time while producing and displacing fluids within the reservoir. Schlumberger ECLIPSE is one of the commercial simulators available in the market. Dynamic reservoir models for gas condensates can be constructed mainly in one of the two different ways, black oil or compositional simulation. ECLIPSE differentiate these two simulation options in to two different simulators which are E100 and E300 respectively. Black oil simulation, which is used in this thesis, is a simpler simulation mechanism where the oil and gas components are not separately accounted throughout the simulation but as a whole, however compositional simulation mainly focus on changes in composition with decreasing temperature and pressure and changes the PVT properties of the gas with changing composition by using an Equation-of-State parameter.

According to the Fevang, Singh & Whitson (2000), black oil simulators for gas condensate reservoir proves useful in many cases by comparing it with the compositional model. The findings of this paper suggest that black oil simulators can be used even in gas cycling simulations however the effect of gravity should be negligible otherwise the resultant simulation can be erroneous.

After the construction of the fluid model the model should be adjusted with the available data to provide an accurate model to study. This adjustment process is called history matching and the aim is to find an acceptable reservoir model and make future predictions. Two different methods can be used in history matching process. The first one, which is most commonly used and also used in this thesis, is the manual history matching and second one is automatic. In manual history matching, engineers adjust the parameters manually by the outcome of the previous model. In automatic history matching idea behind is the same, where the outcome of the previous model is compared with the actual data and adjusted accordingly, however the computer is responsible for the adjustment. (Ertekin, Abou-Kassem, & King, 2001)

In history matching processes, porosity, permeability, relative permeabilities for different phases can be changed to reach and acceptable reservoir model. Relative permeability is a factor can be defined for each phase which states the flow amount for different phases. It is crucial for gas condensate reservoirs since the oil and gas relative permeabilities suggest which phase to flow. If a relative permeability of oil is very low, evolved liquid around the wellbore cannot flow easily thus forming a blockade. Some techniques for changing the relative permeability proposed in literature to increase the production and they will be discussed in the next section.

2.3. Production Strategies and Remediation Techniques

The history matched model should use to determine the future production scenarios. These production scenarios can be the combination of both production and injection. For gas condensate reservoir, gas and water injection are common applications to maintain reservoir pressure. According to El-Banbi (2000), water injection in gas condensate reservoirs is more advantageous than the gas injection due to economic reasons and it is a viable option however gas injection is the good method to increase condensate recovery.

Ali (2014), states that there is other treatment methods for gas condensate blockage other than injection of water or gas, such as methanol treatments, wettability alteration and hydraulic fracturing however these treatment methods are well-scaled were only the blockage around wellbore can be treated but the other parts of the reservoir stays in the same condition.

Asgari A. et al (2013) states that methanol treatment can increase gas relative permeability about 1.3 to 1.6 thus increase the gas productivity.

According to Sheydaeemehr (2014), the wettability alteration proved useful in a giant gas condensate reservoir by changing the wettability of the rock to intermediate-wetting state from strongly liquid wetness. Although the results are promising, they are also backing up the Ali (2014) where the treatment radius of effect ends at 5 m away from the wellbore.

CHAPTER 3

STATEMENT OF PROBLEM

The aim of this study is to compare different production strategies that will optimize the production of a gas condensate field where condensate blockage occurs in the reservoir due to decrease in the reservoir pressure. The optimum production scenario is thought to produce the precious condensate as much as possible without letting its evolution in the reservoir.

The field chosen as the case for the study has been producing more than 40 years and the drilling activity started at 1955 in this offshore field. While production still continues in the field, it is known that some of the wells were abandoned due to condensate blockage around wellbores. Condensate drop-out is caused by the decrease in bottom-hole pressure.

The goal of this thesis is to understand the working mechanism of a gas condensate reservoir by using data obtained from an existing field. For this reason a commercial black-oil simulator, a geological modelling software and a fluid property simulator are used to create geological and fluid models which are used to assess several production strategies that can be a remediation option for the condensate drop-out/blockage problem in the reservoir.

CHAPTER 4

DATA GATHERING AND PROCESSING

In this chapter data gathering and the quality assessment of the data at hand is explained. Some major data sets about the reservoir such as well names, locations, maps and well cross-sections along with production data submitted to the author beforehand by the company operating the field. Although majority of the data has been submitted to the author some other data are produced by using equations, interpretations and assumptions.

4.1. Well Data Analysis

From the given well location maps and coordinates firstly the well locations are gathered. This data are used for constructing the geological model in Schlumberger's PETREL. Since no well deviation survey is available it is assumed that all wells in the field were drilled perfectly vertical. From the well cross-sections the depths of the formation tops are found out and necessary formation tops are used to create input files for PETREL. As mentioned before the main focus of this study is 6^{th} layer therefore tops of 5^{th} and 7^{th} layers are also taken into account in order to find thickness of the layers and the structural pattern. Addition to the drilling, geographical data, total depth of the wells, perforation levels with perforation dates along with the spud date are collected in order to use during history matching process.

4.2. Production Data Analysis

Monthly production data are supplied by the operator company. The data set covers all production done in the field as form of monthly total production of each well and each hydrocarbon fluid (gas, condensate, and oil) coupled with water production and well status. Wells operate only a few days in some months which are identified and for the goodness of history matching additional zero production days have been entered as input file in Schlumberger's ECLIPSE.

4.3. Fluid Data Analysis

Table 1 shows the fluid compositional data which is given by the operator company. Although compositional analysis seems enough, the conditions that the fluid sample is taken is unknown. Due to high methane amount it is assumed that this fluid sample is taken from the separator conditions which are not known either.

Table 1. Compositional Fluid Properties

Component	Mole Percent	Molecular Weight	Critical Pressure (psia)	Critical Temperature (°R)
Methane	93.67	16.043	666.4	343.0
Ethane	2.2	30.07	706.5	549.59
Propane	0.89	44.097	616.0	665.73
iso-Butane	0.5	58.123	527.9	734.13
n-Butane	0	58.123	550.6	765.29
iso-Pentane	0.23	72.15	490.4	828.77
n-Pentane	0.03	72.15	488.6	845.47
Hexane	0.11	86.177	436.9	913.27
Heptanes+	2.14	144	360.7	1023.89
Carbon Dioxide	0.23	44.01	1071	547.58
Nitrogen	0	28.013	493.1	227.16
Oxygen	0	31.999	731.4	278.24
Air	0	28.963	546.9	238.26
Mixture	100	19.84	659.82	369.31

CHAPTER 5

GEOLOGICAL MODEL

5.1. Constructing the Geological Model

The simulation process starts with the geological model of the field. In this thesis Schlumberger's PETREL software is used to create geological model of the field. Well locations, layer tops, fault locations, boundary of the field are the starting points of the geological modelling. In this thesis 85 wells for 3 different layer tops and boundary were used to create the surfaces. The shape of the top surface shown in Figure 4.

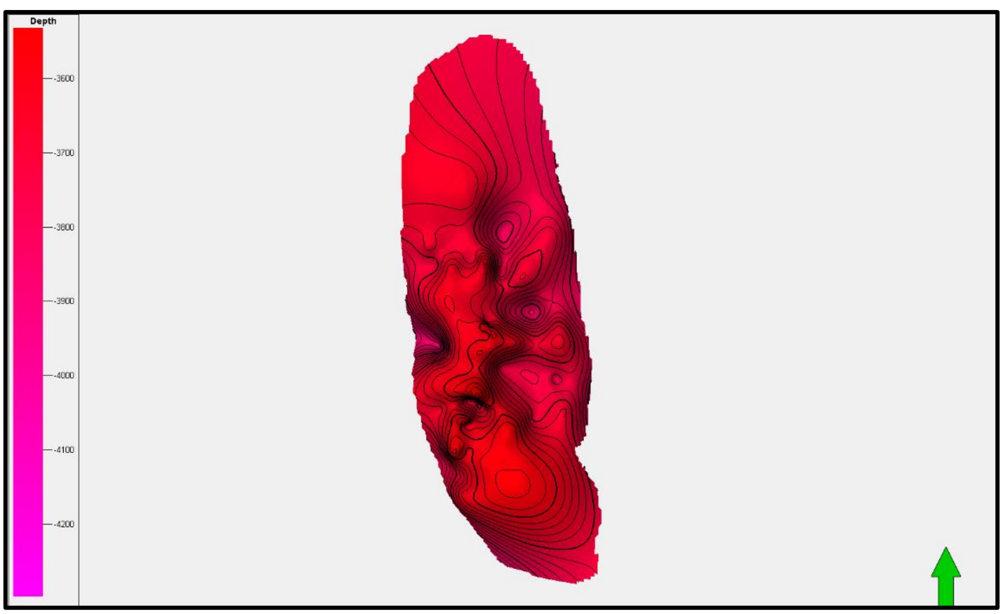

Figure 4. Geological Model Surface (Vertical Exaggeration = 5)

After creating the surfaces, blocks and zones should be created. For the blocks, 3 fault zones defined in the PETREL based on the available fault maps. The first one is trending on NNW-SSE direction and forms the western boundary of the reservoir. After the first fault second and third one are defined to the model. The second and third faults are parallel to each other and they are forming Northern and Southern boundaries of the second block which defines the thesis main focus area. The faults are trending NEE-SWW and they are connecting with the first fault. Faults are shown in Figure 5. One should note that the dips, slip amount and type of these faults are not known, therefore faults are assumed to be vertical and crosses all the layers in the reservoir.

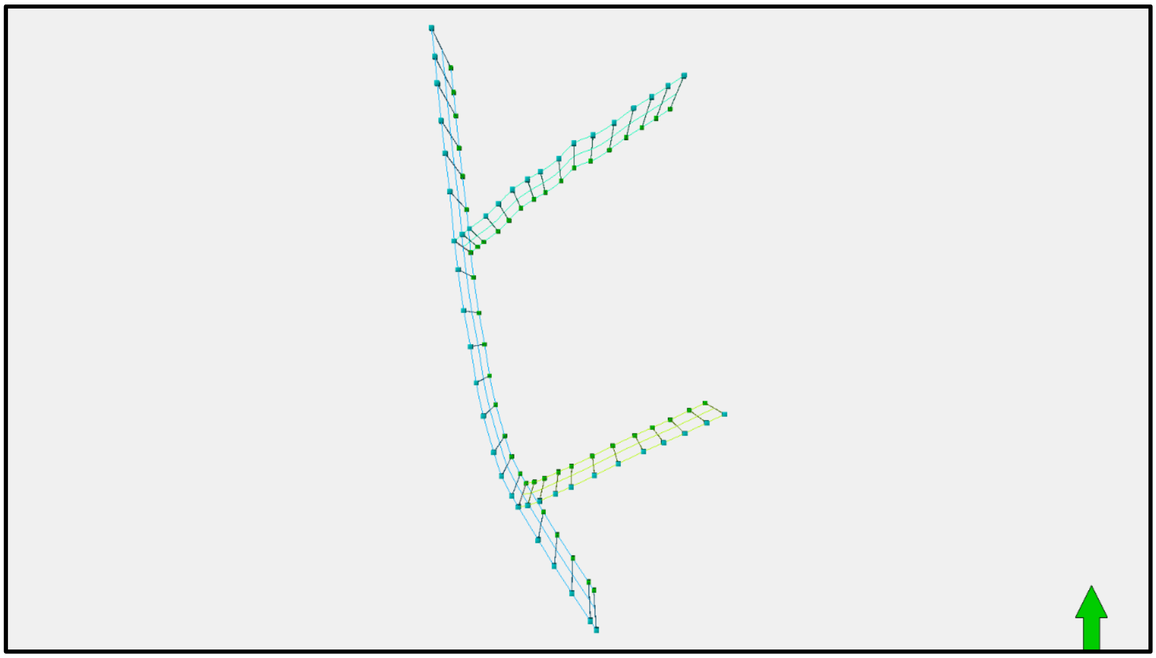

Figure 5. Faults

Next step for the creation of the model is the generation of the zones. Surfaces were created with the well tops from different layers. These well tops are identified from the drilling logs of the wells. Depths of each horizon encountered in each well are different therefore the thickness of each zones are different throughout the field. In order the create the zones from surfaces, PETREL uses top and bottom depths of each well as known points and distribute them across the field by using Kriging method. Grids are also generated during this step. The properties of the reservoir are entered in each grid. The grid numbers of this field is 31, 83 and 12 in X, Y and Z directions respectively. Total number of grid is therefore 30,876. The zones are shown in Figures 6 - 11. Also in Table 2 average depth, thickness and volume values can be seen.

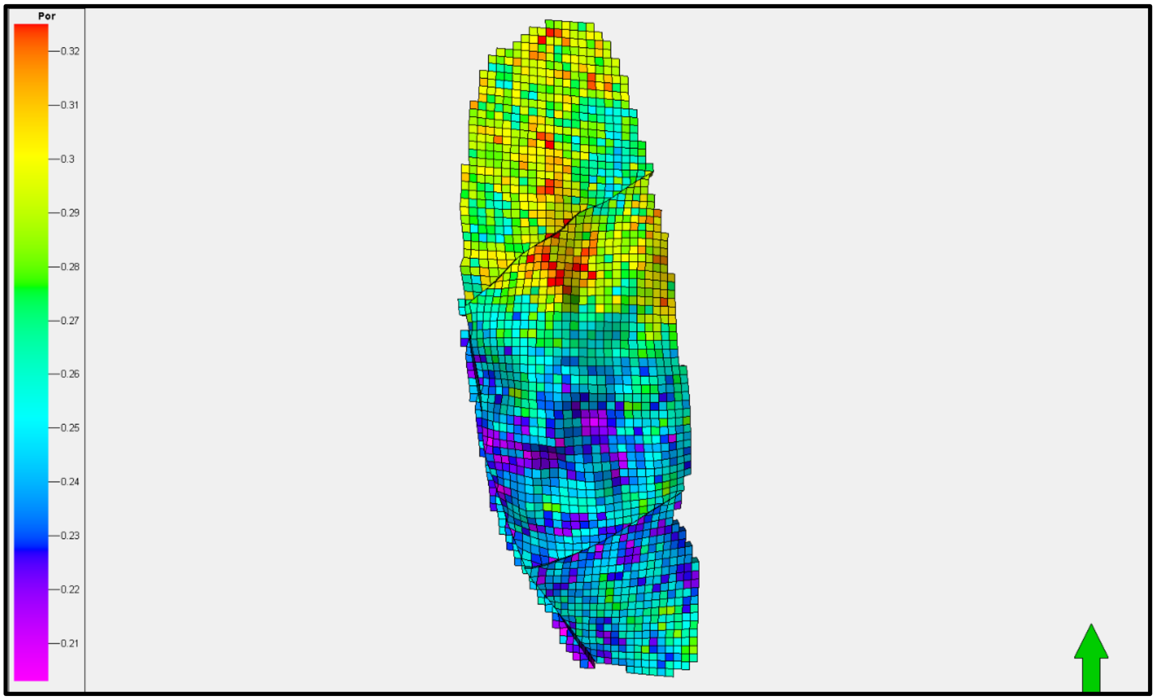

Figure 6. Top view of Zone 1 (Vertical Exaggeration = 3)

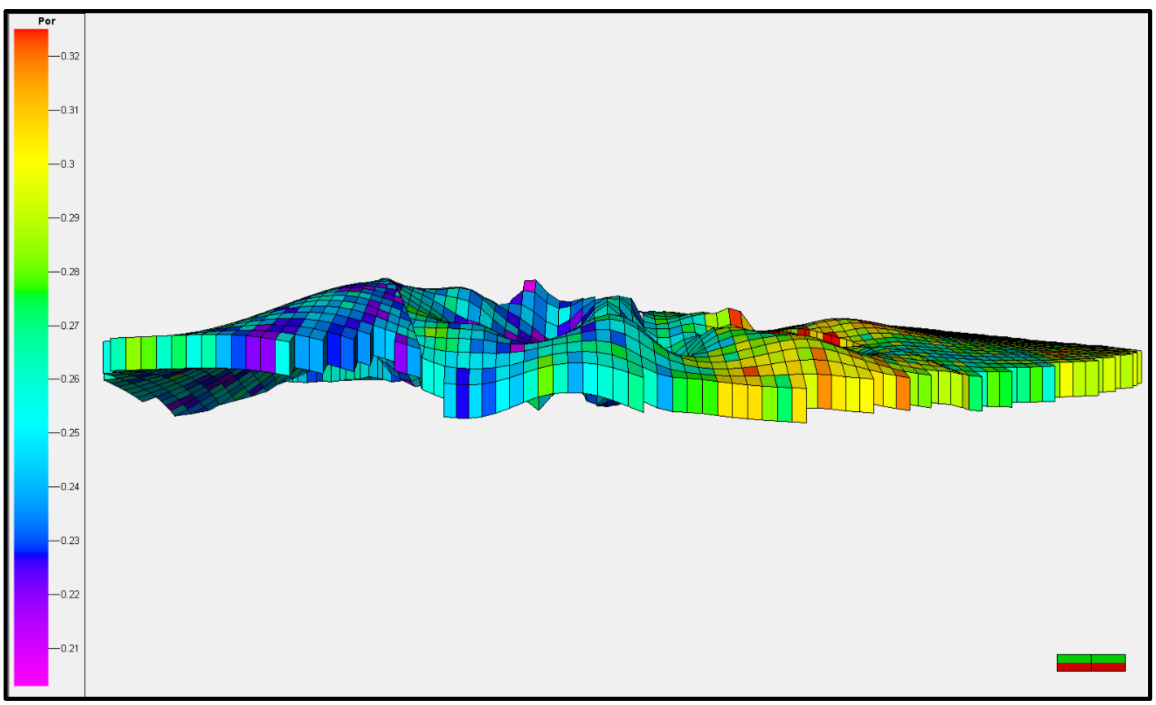

Figure 7. Side view of Zone 1 (Vertical Exaggeration = 3)

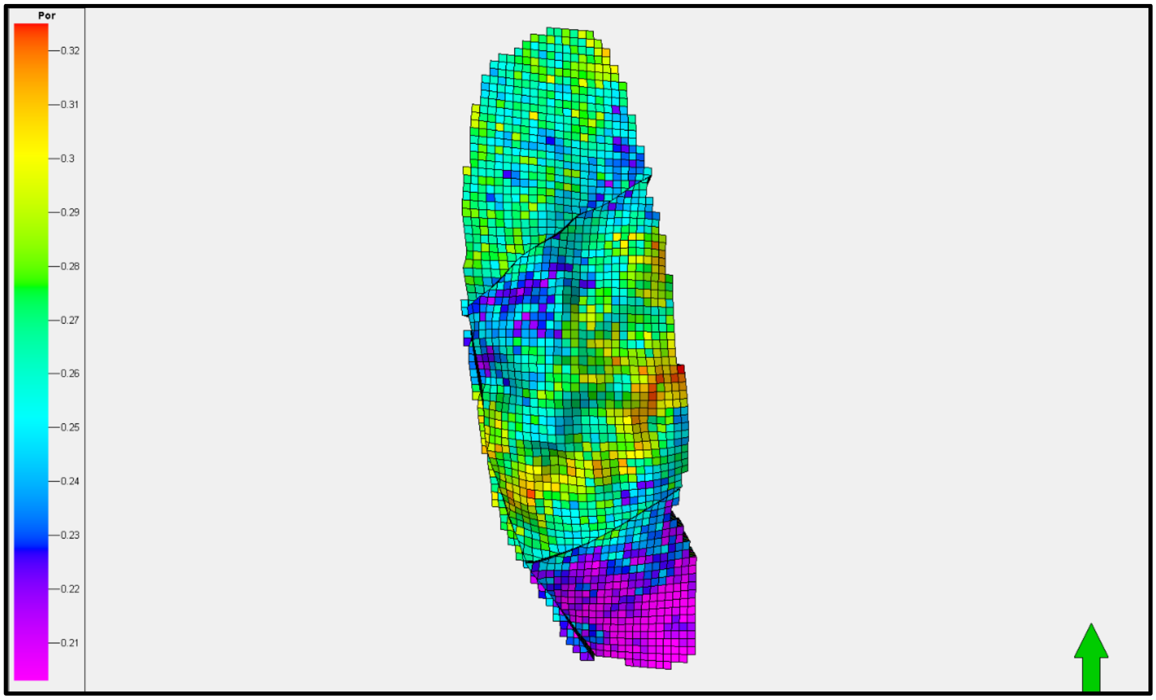

Figure 8 Top view of Zone 2 (Vertical Exaggeration = 3)

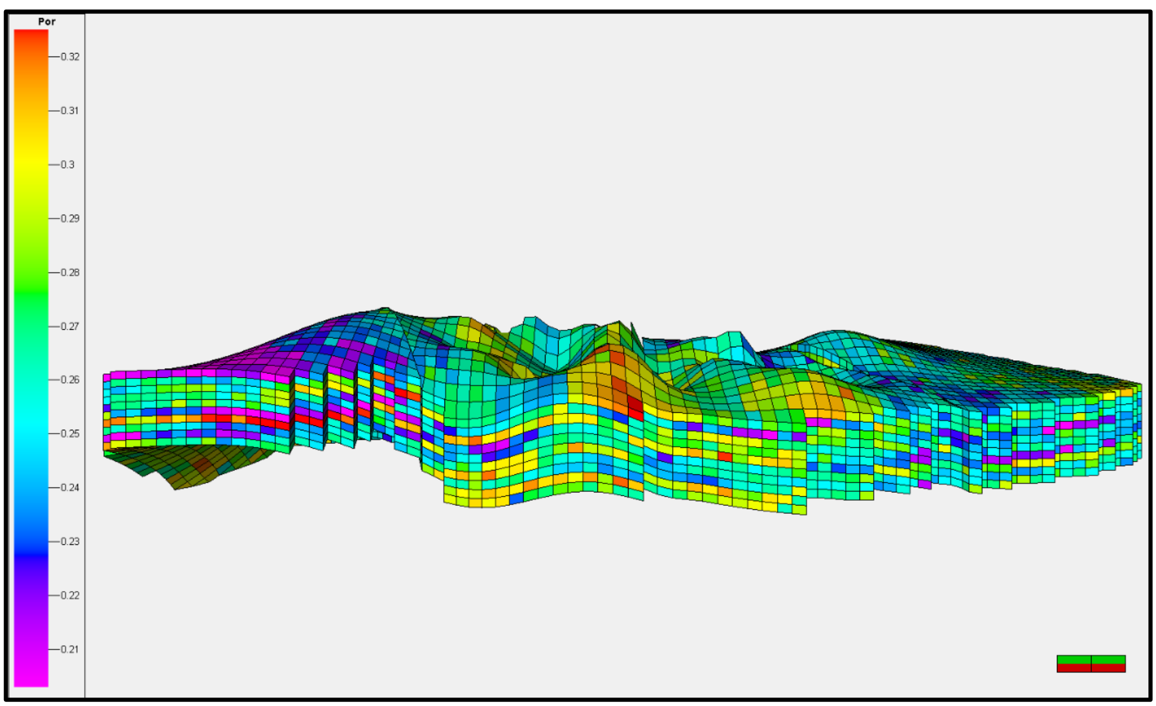

Figure 9 Side view of Zone 2 (Vertical Exaggeration = 3)

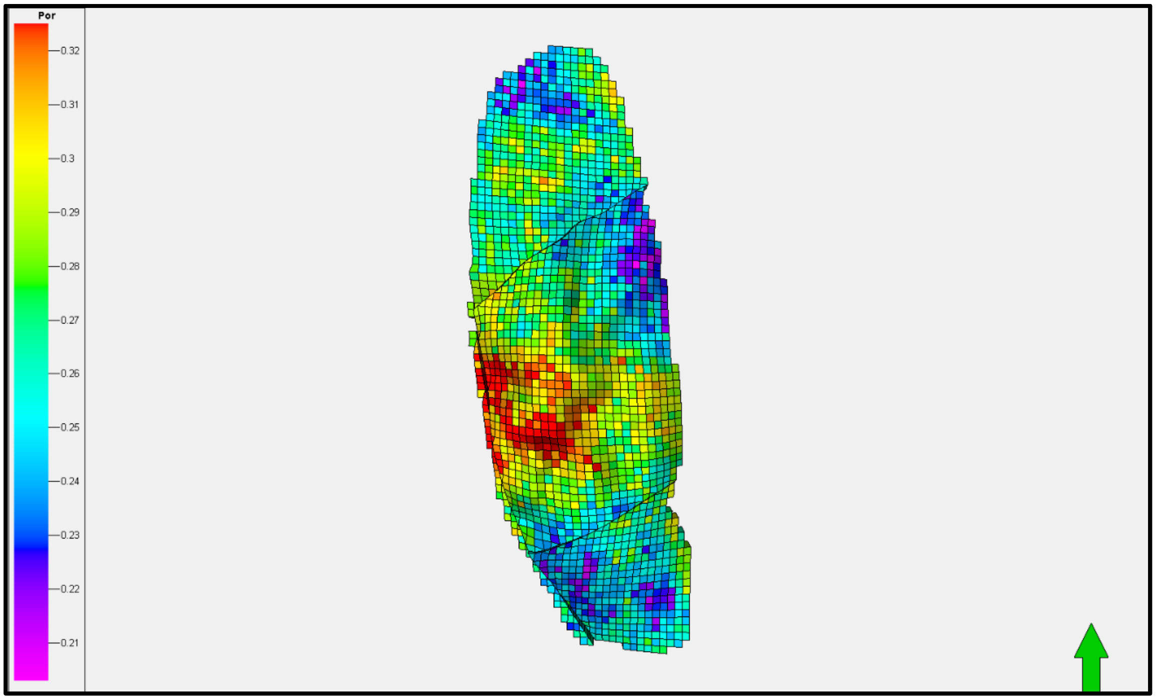

Figure 10 Top view of Zone 3 (Vertical Exaggeration = 3)

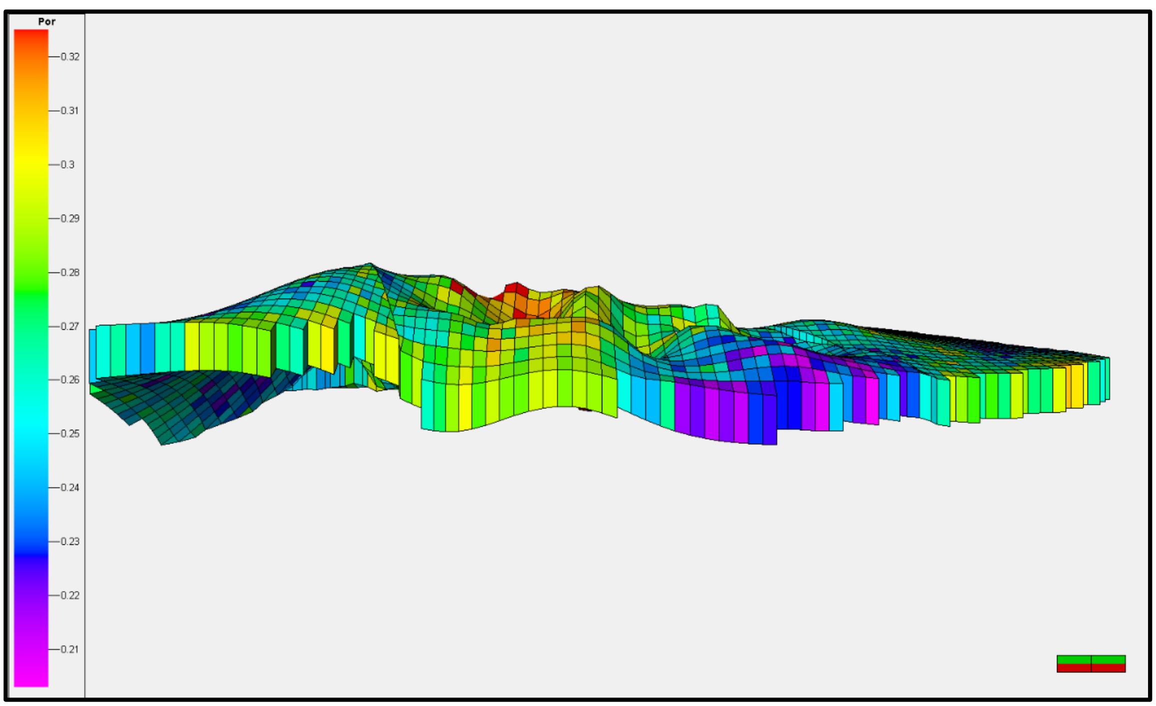

Figure 11 Side view of Zone 3 (Vertical Exaggeration = 3)

Table 2. Average Data for each zone at Block#2

Zone	Average Depth (m)	Average Thickness (m)	Average Volume (m^3)*
Zone#1	3694	76	730.36
Zone#2	3770	195	1873.95
Zone#3	3965	109	1047.49

(*Area taken as 9.61115×10^6 m^2)

As stated earlier, the 6th layer and 2nd block is the main area of focus in this study. Zone 2 corresponds to the 6th layer and the other zones 1 and 3 are set inactive in order to achieve no flow condition. Therefore it is assumed that there is no connection between top and bottom formations. Also Zone 2 is divided into 10 small layers in order to ease out illustration of the simulation outcomes of the model and to simulate vertical fluid transfers in the reservoir. Each layer is identical in thickness but the thickness of the total formation varies throughout the study area.

Reservoir petro physical properties are defined for each block following the gridding step. Permeability, porosity, and net to gross ratio values assigned based on limited core data available and using normal distribution method. During history matching process, these properties were changed and adjusted in order to fit the model to the real case. These changes are mentioned in History Matching chapter.

Pressure values are the first property that is entered by using the Depth versus pressure graph that was submitted by the company. The pressure depth relationship given in Equation 3.

$$\boldsymbol{Depth\ (ft) = 2.2159 \times Pressure\ (psi) - 16.935} \qquad (3)$$

The Equation 3 entered to the calculator tool of PETREL to calculate the pressure values with respect to depth information. Figures 12 and 13 show the pressure distribution of the field.

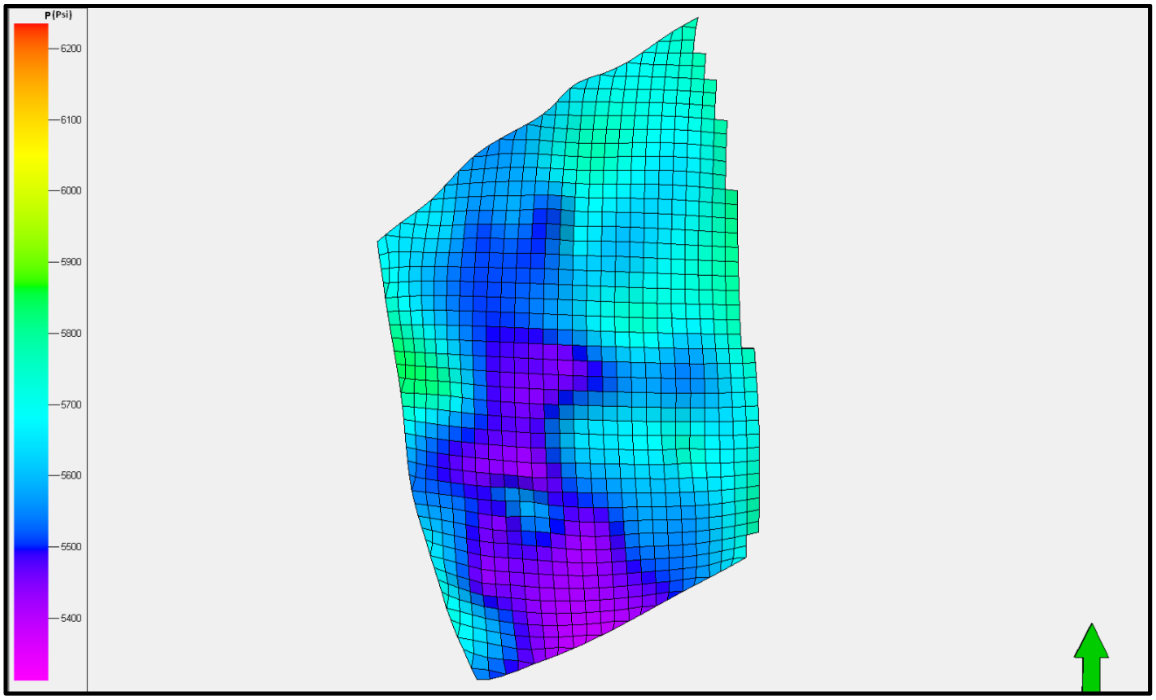

Figure 12. Pressure Distribution Top view

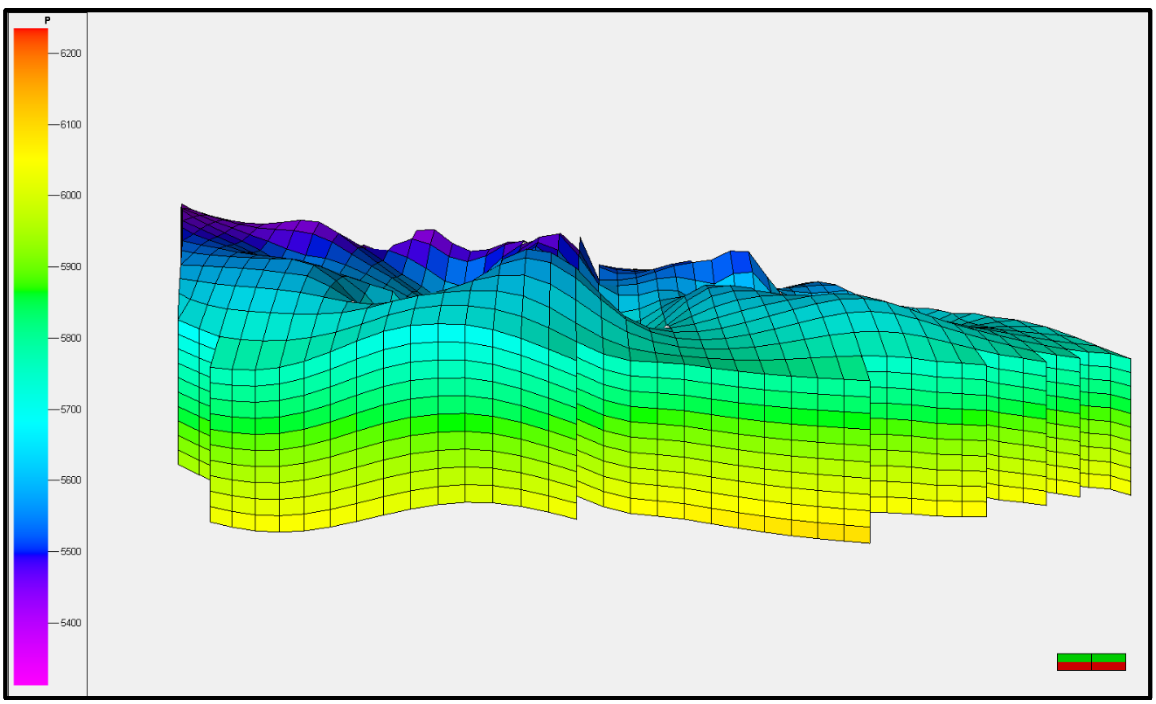

Figure 13. Pressure Distribution Side view (Vertical Exaggeration = 3)

Gas formation volume factor (B_g) is the next property that is distributed to each grid as a function of pressure. Figure 14 shows the relation between Bg and Pressure.

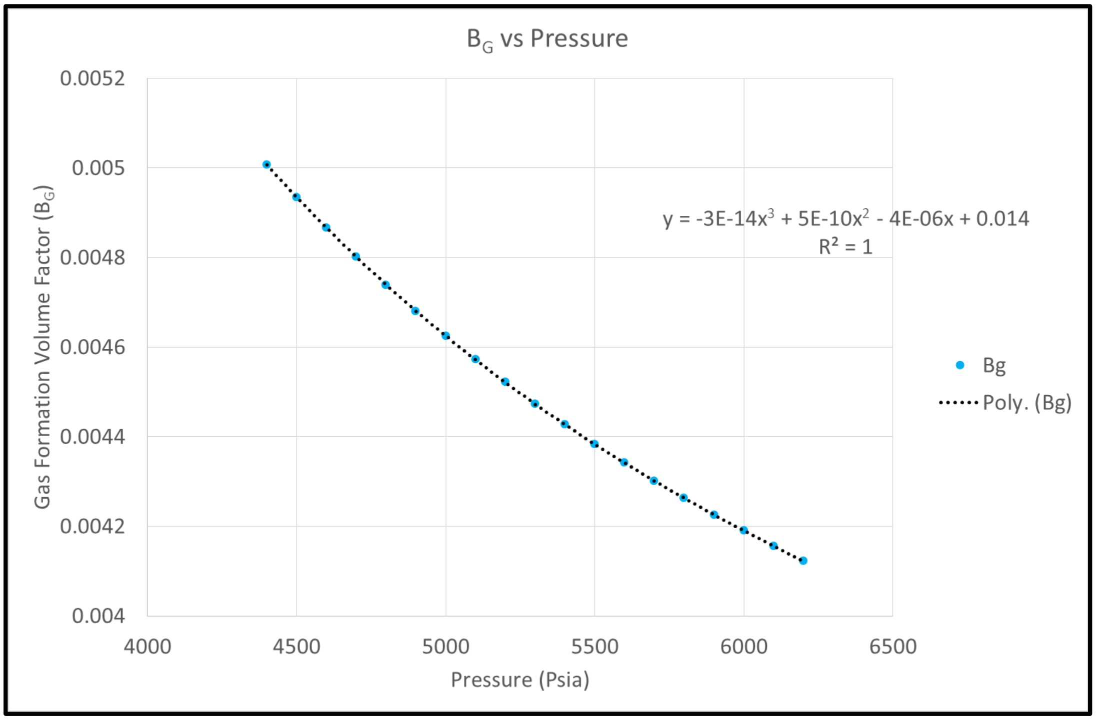

Figure 14 Bg vs Pressure Graph

Figures 15 and 16 represent the Gas formation volume factor distribution of the field.

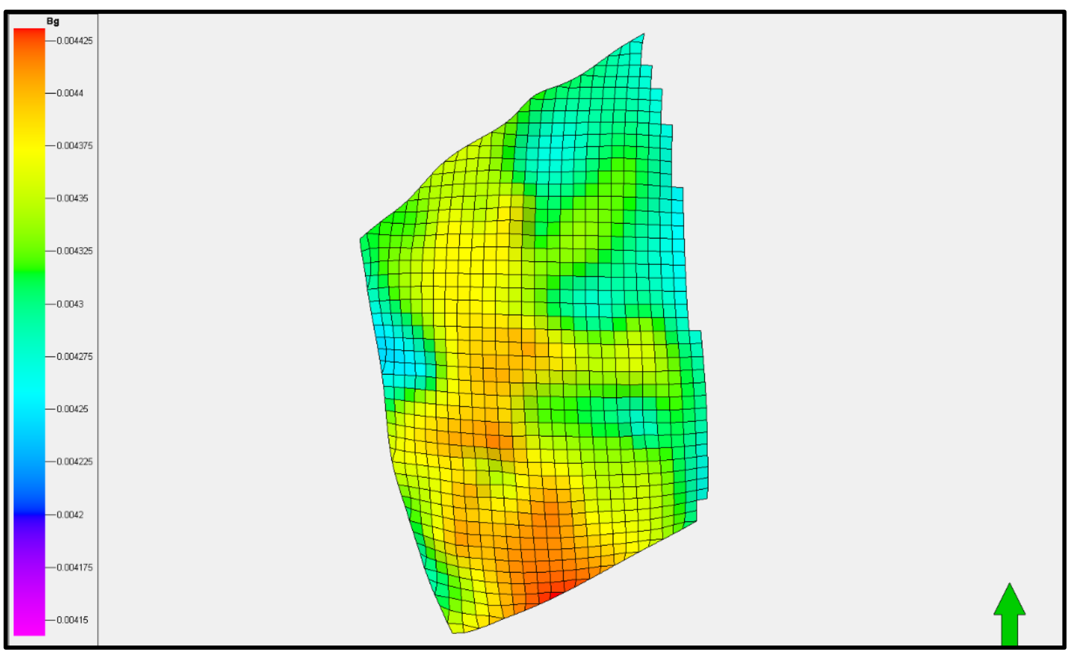

Figure 15. Bg Distribution Top view

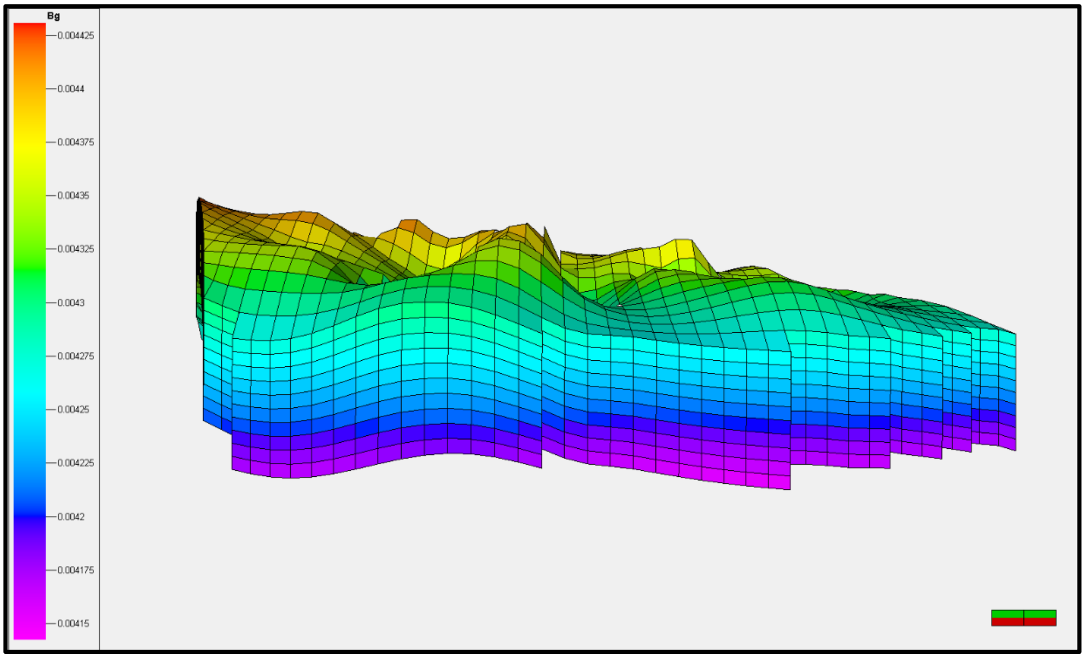

Figure 16. Bg Distribution Side view (Vertical Exaggeration = 3)

Porosity and permeability data of the field were defined in the model by using core analysis of the field. The porosity of the field changes from 0.18 to 0.3 throughout the different locations of the field. First of all, it was defined as normal distribution with mean and standard deviation values are 0.26 and 0.03 respectively. After distribution is created and with kriging method all the grid are assigned a value then this distribution has been done by keeping the known core location data. Figures 17 and 18 show the porosity distribution of the field.

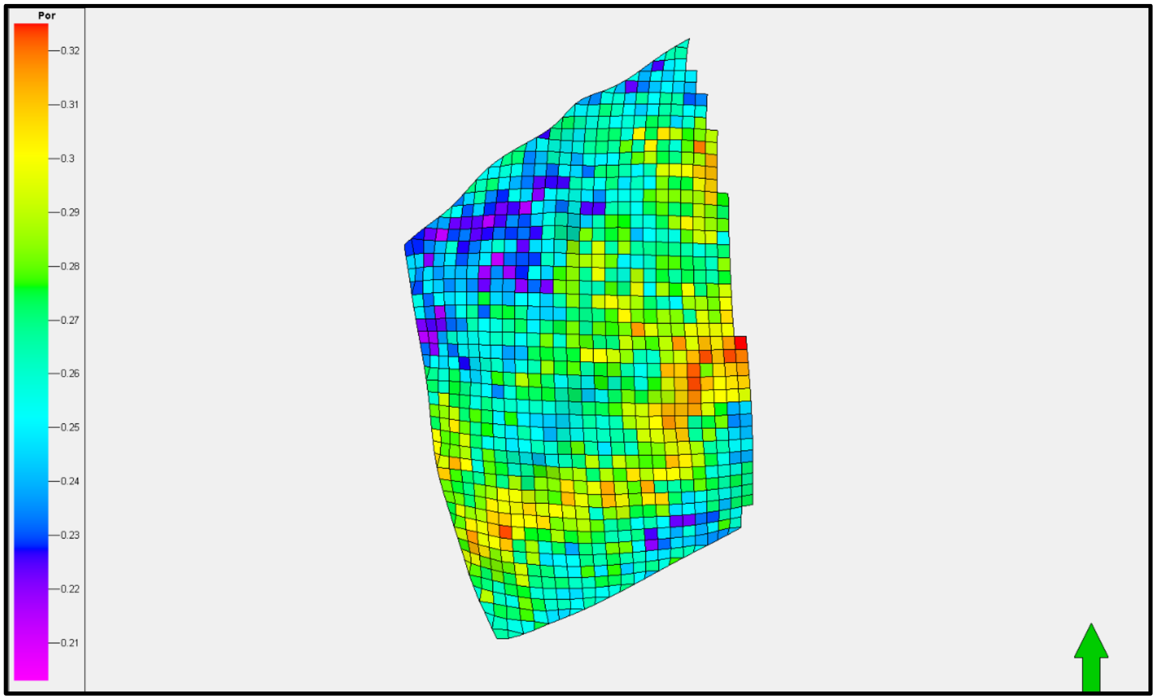

Figure 17. Porosity Distribution Top view

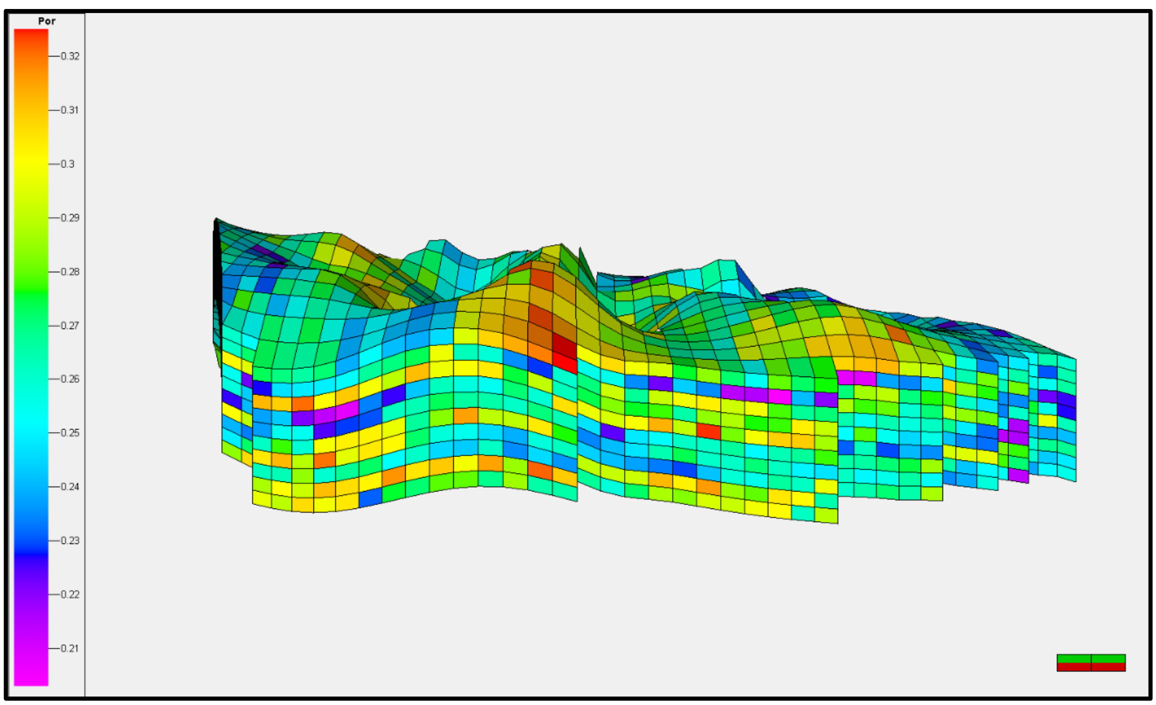

Figure 18. Porosity Distribution Side view (Vertical Exaggeration = 3)

For the permeability it is assumed that the field has isotropy where X, Y and Z directions permeability are same and its lowest value is 30 mD and the highest seen permeability is 195 mD. However the core data analysis shows that the mean is around 40 mD. The permeability distribution can be seen in Figure 19.

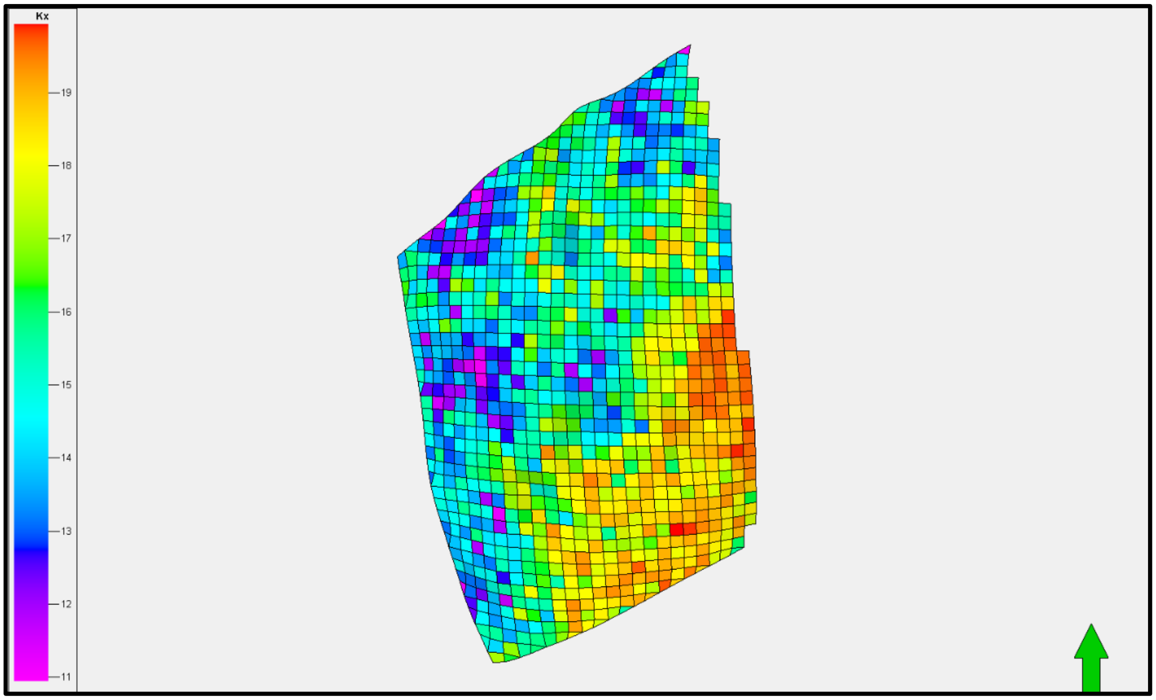

Figure 19. Permeability Distribution

Net to Gross ratio (N/G) data available for most of the wells. From the well logs, the net thickness of the 6^{th} layer and the total thicknesses were obtained, so by using simple mathematics N/G for each wells are calculated and submitted to PETREL by well properties. N/G property is distributed to the whole field. Figures 20 and 21 show the NTG distribution of the field.

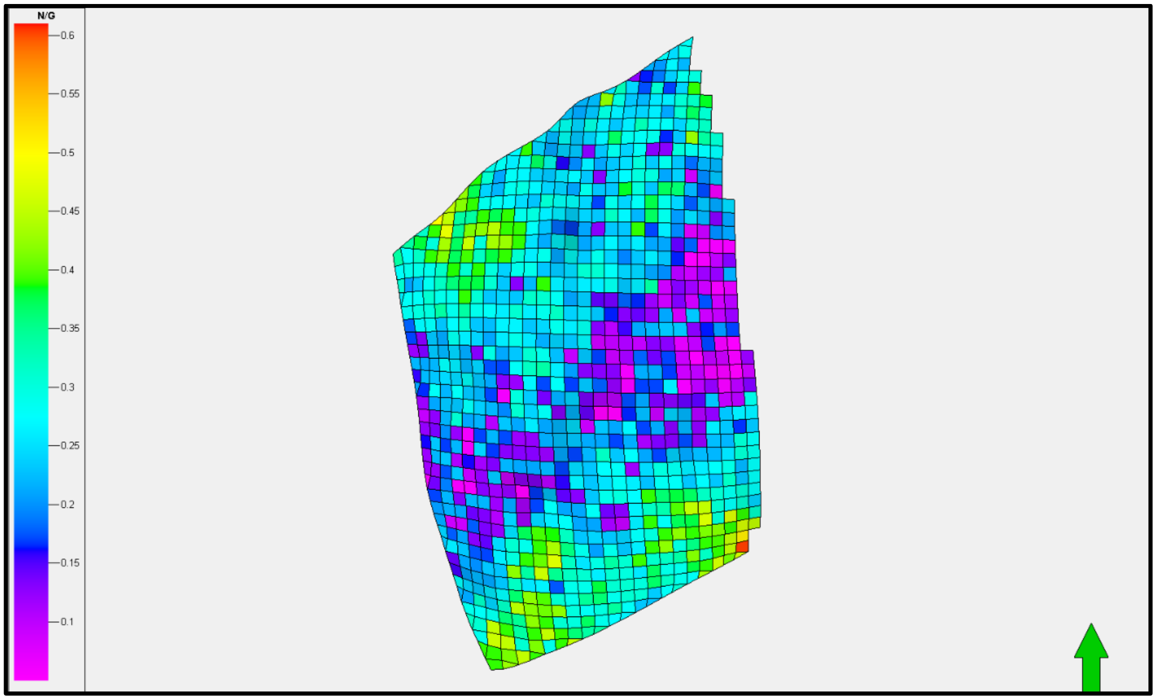

Figure 20. Net to Gross Ratio Distribution Top view

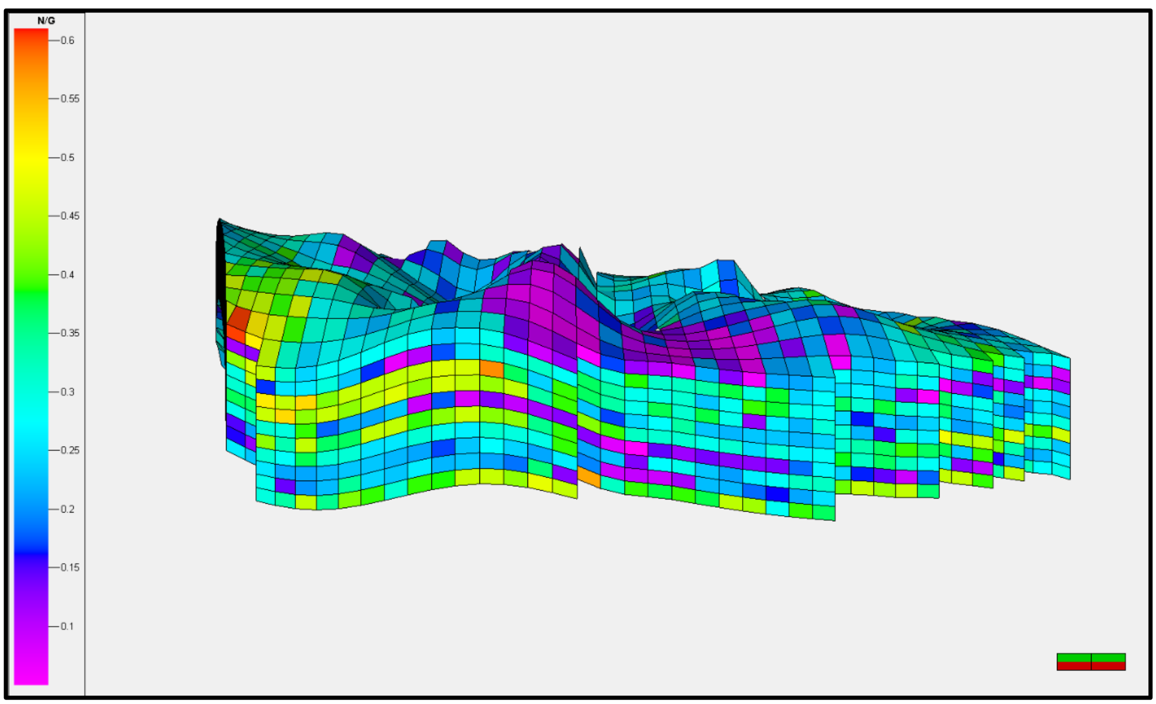

Figure 21. Net to Gross Ratio Distribution Side view (Vertical Exaggeration = 3)

After the property definitions of the model, the depth of the water and gas contact (GWC) is required to be calculated in order to understand the phase distribution of field. The reservoir consist of gas and water at initial stage and there is no oil volume presented in the field other than the ones that is in vaporized state. The depth of GWC was unknown but from pressure and gas property data the depth of GWC was found. Equation 4 was used to find the depth.

$$\mathbf{0.433 \times D + 14.7 = PG_{Gas} \times D + C} \qquad (4)$$

Where;

PG_{Gas} = Gas phase pressure gradient, in psi/ft

C is a constant, in psi

D is depth, in ft

PG_{Gas} of this field is taken as 0.114769 psi/ft by using conversion factors to the gas density 16.53 lb/ft^3 which was given by the company. The constant is determined by solving Equation 4 by using known pressure at a known depth and it is equal to 4167.6 psi. At last the depth of GWC found as 13050 feet (3977.64 meters) with using the PG_{Gas} and Constant values. Figure 22 shows the GWC of the field from 5th layer to 10th layer Zone 2. These layers are artificially created by dividing zone 2 in to 10 equal layers. The reason of this division is to able to make fine tuning in the zone 2.

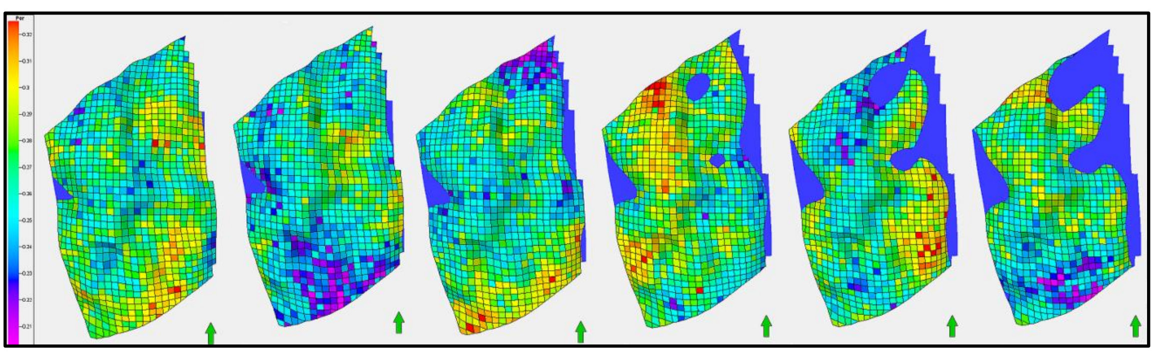

Figure 22. Gas Water Contact in different layers of Zone 2

Last step for the geological model is to define perforations for each well. Company provided author with the perforation parameters such as depth, thickness and opening date.

Even though data for more than 85 wells are available to create the geological model of the field, not all of this wells are used in flow model due to their locations, unavailability of production data or due to different production phases. Figure 23 shows all the wells available and Figure 24 shows only the wells that are used in flow model for the 2nd block. The reasons for unused wells can be listed as:

- Some of the wells are located in different blocks other than Block#2.
- Some of the wells are located outside of the boundary.
- No completion data: perforation depths, dates etc.
- No production history or unavailable production data.
- Some of the production wells does not produce gas phase.

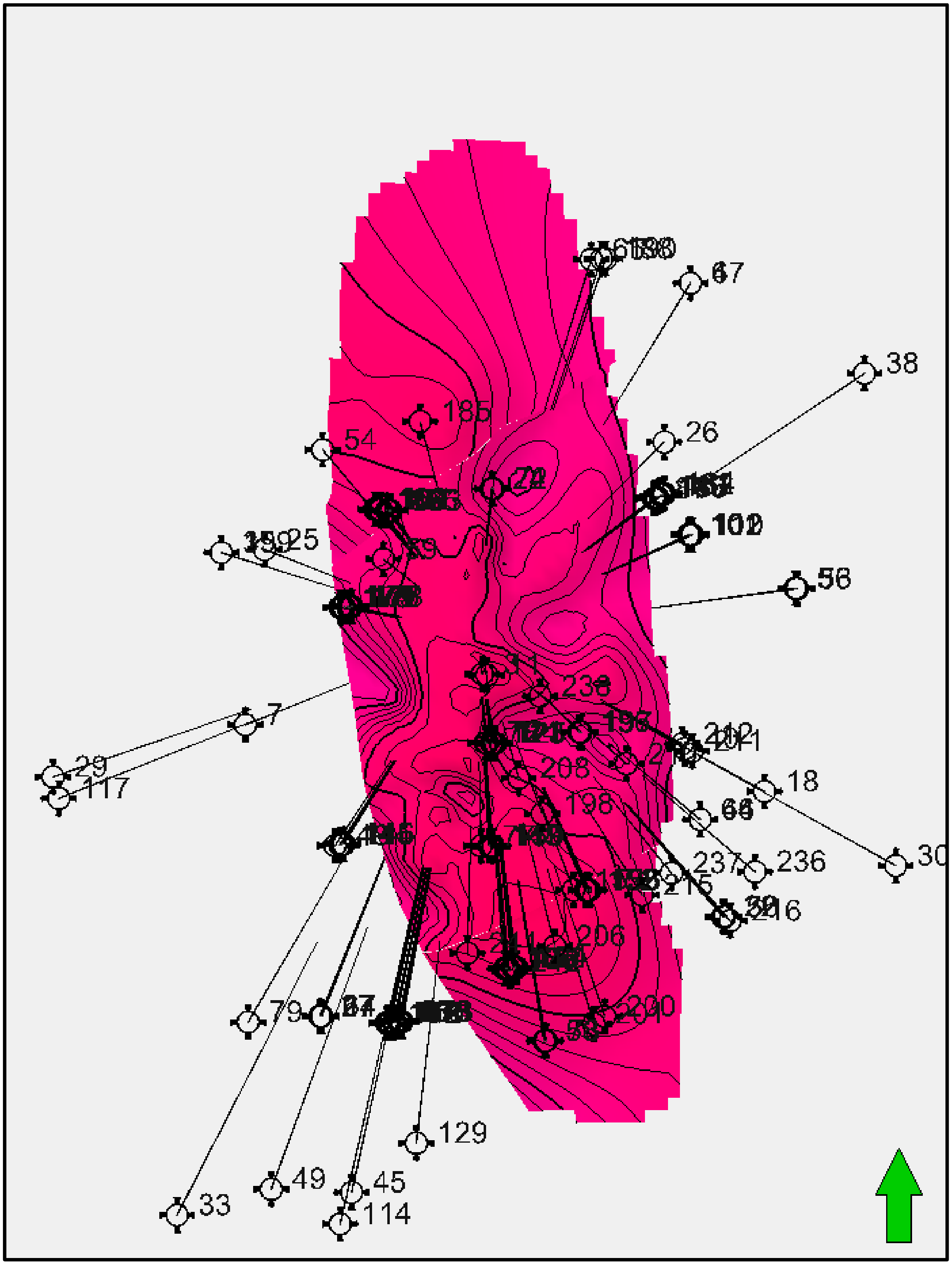

Figure 23. Well locations

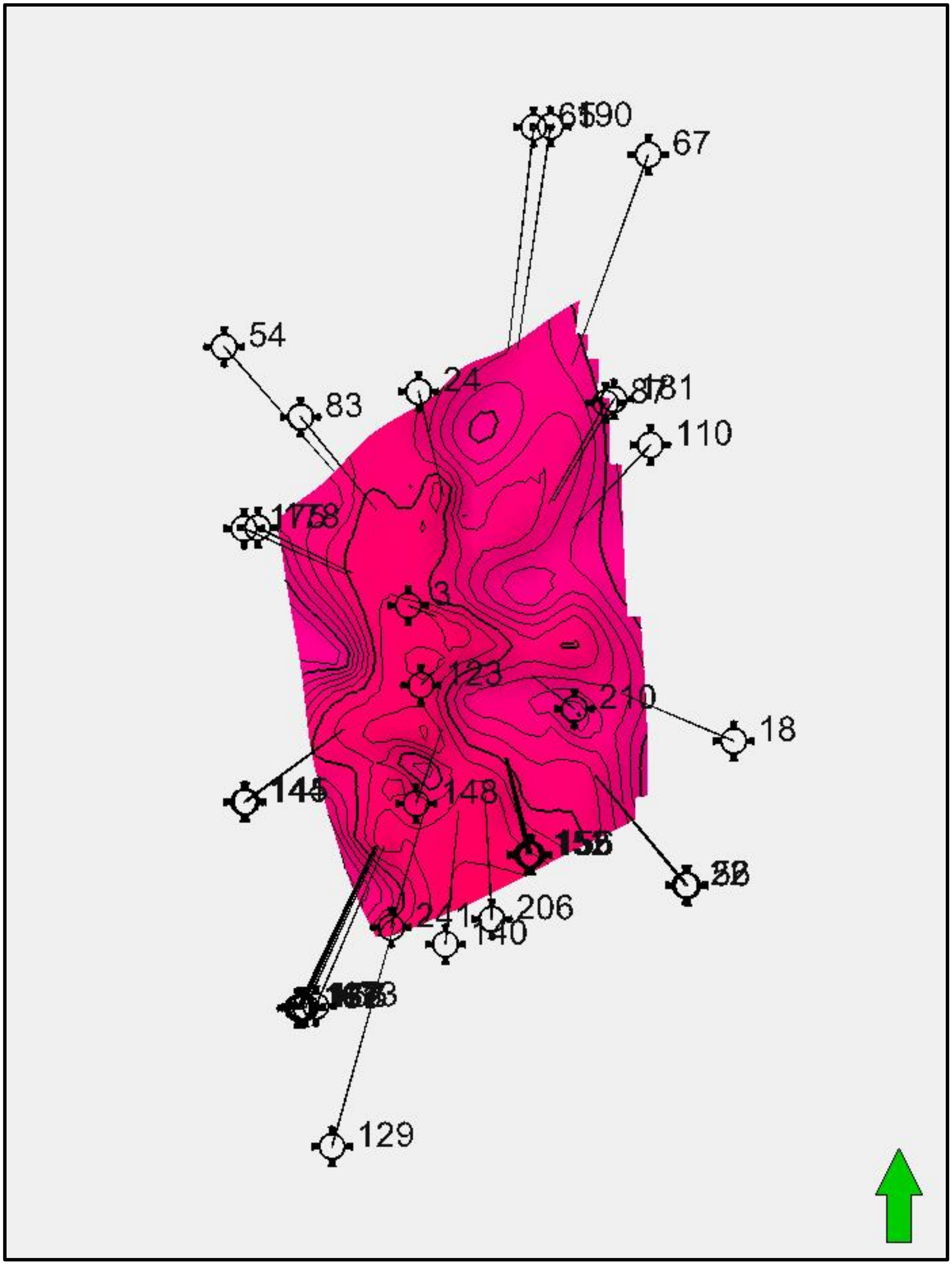

Figure 24. Well locations flow model only

5.2. Verification of Geological Model

Creating the geological model is the first step for a simulation. But one must understand whether the model is representetive or not. In order to verify the geological model some known data should be compared the calculated values of the model. These data could be anything that does not involve the time dependent changes such as pressure. Reservoir area, pore volume, original fluid in place are the ones that one can be calculated and compared with the data at hand. Therefore PETREL's volumetric calculation option is used.

In volumetric calculation option PETREL asks user for some information such as;

- Location of fluid contacts
- Porosity and N/G of the field
- Saturation values
- Surface fluid conditions

Other than saturation and surface fluid condition values, all of the above information were defined to the system. The saturation values that are entered is the connate water saturation (S_w) which is 0.24.

Surface fluid conditions could include information such as Fluid Formation Volume Factor, Solution Gas Oil Ratio (R_S) or Vaporized Oil Gas Ratio (R_V). Since the field is a gas condensate field the R_V value should be entered to the software for the volumetric calculation and it is given as 0.000127. Original values and the calculation results can be seen in Table 3.

Table 3. Volumetric Calculation Comparison

Variable	Given Data	Calculated Data	Ratio (Calculated/Given)
Area (10^6 m^2)	9.635	9.61115	0.997525
Net Volume (10^6 m^3)	578.14	429	0.742035
Pore Volume (10^6 rm^3)	128	100	0.78125
Original Gas In Place (10^{11} ft^3)	9.95418	6.2784214	0.630732

The values in Table 3 have shown that there are differences in the obtained values and the data given by the operating company. It was thought that this difference is due to the simple methodology that was used by the operating company calculations. Although calculated and given area values are very similar, the differences in the bulk volume is too much. The reason for that is the net thickness values used by the company for the field are taken as total thickness as well. It can be understood by looking at the net volume comparisons. The company has also taken a uniform net thickness through the field, on the other hand the static model considers the change in thickness values throughout the field as shown in the Figure 20. The change in net to gross ratio for each grid without simplifying that distributed property into a value results with a better net volume values and since gas in place is a function of volume the gas in place values also not similar enough.

Also in the simulation case gas formation volume factor (B_G) is also distributed and taken into calculation different in each grid block however the company uses only one B_G value for the Original Gas In Place (OGIP) calculation. The additional difference between given and the calculated data comes from this difference.

CHAPTER 6

DYNAMIC MODEL

Constructing the dynamic model for a simulation is the next step after the construction of the geological model. It is a complicated step that accompanies the geological model and well production data as well. The dynamic model was constructed by using Schlumberger's ECLIPSE software. ECLIPSE software have commonly used two different simulation programs ECLIPSE E100 and E300. E100 is a black-oil simulator which is simple than E300, compositional simulator. In this thesis work ECLIPSE E100 is used as main simulation software. In addition to the main flow simulators, ECLIPSE have different sub-programs such as ECLIPSE PVTi where fluid properties such as; PVT properties, phase diagrams, critical values, and saturation tables can be created. PVTi helps user to define fluid properties easily by a user friendly interface. The other sub-program that is heavily used is ECLIPSE FloViz. In FloViz users can visualize the simulation outcomes of different properties for each time step that ECLIPSE gives as output.

6.1. Defining Fluid Properties

In order to define fluid properties first fluid composition should be understood, then defining the changes of the fluid composition while changing pressure or temperature or both. In order to create the reservoir fluids phase diagram and other properties regarding as fluid properties Schlumberger ECLIPSE PVTi program was used. In this program, at startup fluid compositional analysis should be given. The compositional data of the reservoir fluid was given in Table 1. Table 4 shows the input data for PVTi program.

Table 4. Input Data for PVTi software

Component	Mole Percent	Molecular Weight	Specific Gravity
C1	93.67		
C2	2.2		
C3	0.89		
iC4	0.5		
nC4	0		
iC5	0.23		
nC5	0.03		
C6	0.11		
C7+	2.14	144*	0.777
CO2	0.23		
N2	0		

*Calculated by using Riazzi-Daubert correlation

From this data PVTi software use the built-in library to find out the molecular weight, specific gravity and calculating the critical properties of each component and total gas sample.

After forming the fluid sample PVTi software needs some observation or experimental data to further understand the fluid. In order to achieve this, Constant Volume Depletion (CVD) and Differential Liberation (DL) experiments were given to the software. Table 5 and 6 shows the input data for this experiments respectively. The reservoir temperature was given as 191.5 °F and all the experiments based on this temperature value and it is assumed that temperature of the reservoir is always constant.

Table 5. Constant Volume Depletion Data

Pressure (psia)	Gas Density (lbm/ft3)	Pressure (psia)	Gas Density (lbm/ft3)
15	0.047	3900	13.33
100	0.314	4000	13.575
400	1.296	4100	13.813
500	1.637	4200	14.045
1000	3.43	4300	14.271
1500	5.337	4400	14.49
2000	7.267	4500	14.703
2100	7.645	4600	14.911
2200	8.02	4700	15.113
2300	8.389	4800	15.31
2400	8.753	4900	15.502
2500	9.111	5000	15.688
2600	9.461	5500	16.553
2700	9.805	6000	17.318
2900	10.47	6100	17.461
3000	10.791	6200	17.6
3100	11.104	6300	17.736
3200	11.409	6400	17.87
3300	11.707	6500	18.001
3400	11.996	6600	18.128
3500	12.278	6700	18.254
3600	12.552	6800	18.376
3700	12.818	6900	18.497
3800	13.078	7000	18.614

Table 6. Differential Liberation Data

Pressure (psia)	Gas Deviation Factor Z	Gas Volume Factor (ft3/scf3)	Gas Density (lbm/ft3)	Gas Viscosity (cp)
15	0.998	1.226	0.047	0.01265
100	0.99	0.182	0.314	0.01271
400	0.959	0.044	1.296	0.01308
500	0.95	0.035	1.637	0.01324
1000	0.906	0.017	3.43	0.01427
1500	0.874	0.011	5.337	0.01567
2000	0.856	0.008	7.267	0.01742
2100	0.854	0.007	7.645	0.0178
2200	0.853	0.007	8.02	0.0182
2300	0.852	0.007	8.389	0.0186
2400	0.852	0.007	8.753	0.01901
2500	0.853	0.006	9.111	0.01942
2600	0.854	0.006	9.461	0.01985
2700	0.856	0.006	9.805	0.02028
2900	0.861	0.005	10.47	0.02114
3000	0.864	0.005	10.791	0.02158
3100	0.868	0.005	11.104	0.02202
3200	0.872	0.005	11.409	0.02246
3300	0.876	0.005	11.707	0.0229
3400	0.881	0.005	11.996	0.02334
3500	0.886	0.005	12.278	0.02378
3600	0.892	0.005	12.552	0.02422
3700	0.897	0.004	12.818	0.02466
3800	0.903	0.004	13.078	0.0251

Table 6 Continued

Pressure (psia)	Gas Deviation Factor Z	Gas Volume Factor (ft3/scf3)	Gas Density (lbm/ft3)	Gas Viscosity (cp)
3900	0.909	0.004	13.33	0.02553
4000	0.916	0.004	13.575	0.02597
4100	0.923	0.004	13.813	0.0264
4200	0.93	0.004	14.045	0.02682
4300	0.937	0.004	14.271	0.02725
4400	0.944	0.004	14.49	0.02767
4500	0.951	0.004	14.703	0.02808
4600	0.959	0.004	14.911	0.0285
4700	0.967	0.004	15.113	0.02891
4800	0.975	0.004	15.31	0.02931
4900	0.983	0.004	15.502	0.02972
5000	0.991	0.004	15.688	0.03012
5500	1.033	0.003	16.553	0.03206
6000	1.077	0.003	17.318	0.0339
6100	1.086	0.003	17.461	0.03426
6200	1.095	0.003	17.6	0.03462
6300	1.104	0.003	17.736	0.03497
6400	1.113	0.003	17.87	0.03532
6500	1.122	0.003	18.001	0.03567
6600	1.132	0.003	18.128	0.03601
6700	1.141	0.003	18.254	0.03635
6800	1.15	0.003	18.376	0.03668
6900	1.16	0.003	18.497	0.03702
7000	1.169	0.003	18.614	0.03735

Following the experiment data definition Phase diagram of the fluid sample is created by the PVTi software. Figure 25 shows the phase diagram.

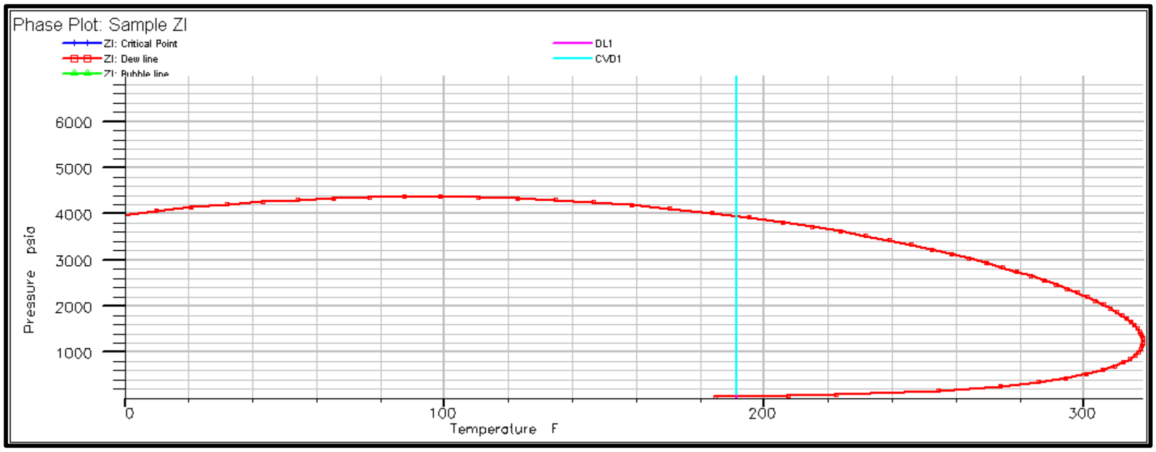

Figure 25. Phase Diagram of given fluid sample

According to phase diagram the dew point pressure for the reservoir temperature (191.5°F) is around 3950 psia. This data are very critical for this study since the oil that was vaporized in the gas phase starts to dissolve at dew point pressure. In order to keep precious condensate in vaporized form the average reservoir pressure must be always greater than dew point pressure.

The next step is to verify the phase diagram and PVT tables which PVTi was created. However, there are nothing to verify this phase diagram at the available data. For the sake of continuing this study it is assumed that the phase diagram is true. Therefore all of the tables that PVTi software was created, treated as true as well.

PVTi software was used to define Density and PVT properties of fluids, Rs versus depth (RSVD) and Rv versus depth (RVVD) tables.

6.2. Construction of the Flow Model

Schlumberger's ECLIPSE is a powerful simulator which could simulate a variety of problems that petroleum engineers can be encountered with. From a dual porosity simulation to CO2 storage, coal bed methane modeling to gas condensate modelling. In order to simulate a specific case special keywords were used. These keywords were entered to different sections;

- Runspec
- Grid
- Props
- Regions
- Solution
- Summary
- Schedule

Runspec section is the opening section of and ECLIPSE simulation. In this section users specify the properties of reservoir such as which types of fluid are found in the reservoir or how many grids are specified in the geological model were given in this section.

In Grid section users specify the grid properties. Which grids are active, what are the values that was assigned each grid block for different properties are the main question that will be answered in this section. In this study PETREL was used to create grid blocks and the properties for each grid block was defined in PETREL therefore all of the necessary grid block properties were exported from PETREL. Only thing is entered in DATA file is the specifying which grid blocks are active by using EQUALS keyword.

Props section is the place where users define fluid properties to the ECLIPSE. Saturation functions, PVT tables for fluids, Density values and rock parameters were assigned in this section. Nearly all of the data should be entered in this section generated from the PVTi software so they have been exported easily. Only the saturation functions for each fluid phase were defined by the author.

Since the connate water saturation is known as 0.24, the other fluids maximum saturation values were set as 0.76. Liquid blockage is very common for gas condensate fields so for the sake of reality flowing oil saturation value is set as 0.3 where water and gas are 0.24 and 0.35 respectively. This data means that in order to produce the formed condensate within the reservoir, 0.3 of the pore volume must have covered by condensate otherwise the condensate is not moving and forming a barrier.

Regions section is an optional section where you can define different regions in the reservoir and even you can make two or more reservoir volumes acts separately within the same layer of the reservoir. In this thesis only 6th layer of the 2nd block set active and it is defined as one reservoir volume.

Solution section is the initializing section and defining some properties that is essential for solving the equations that runs background. EQUIL keyword is used as an initializer for the field where one can define reference depth for pressure, initial pressure and depths of contacts. Other than EQUIL, RSVD and RVVD tables also defined in this section.

Summary section again an optional section however it is the only place where one can specify output data which could be later used in PETREL to create graphs. Without the summary section and its keywords, to gather the values one must search every lines through the print file. This study is relying heavily on the summary section in order to understand the behavior of the reservoir. Field gas production rate to wells production rates for each fluid phase, wells bottom hole pressure data to initial fluid in places were specified.

Lastly the Schedule section where all the observed production, completion and well data were defined. In addition to the observed production/injection data, hypothetical production/injection data could be produced and specified in this section. WELSPECS keyword is to define well name, IJK location of the wells, which is the specified phase of the well. Similar to that COMPDAT keyword is to specify the name of the well, IJK locations of the perforations and the relationship of the well with the reservoir rock. In schedule section events can be specified to a certain date. This helps users to adjust data at hand to history matching process. WCONHIST keyword was meant to specify real production data at certain date for certain wells.

Table 7 shows the wells that is used in fluid model.

Table 7. Information of wells used in fluid model

Well Name	Start Date	Final Date	Status
B3	1 DEC 69	1 NOV 94	Abandoned
B67	1 AUG 78	1 JUN 83	Abandoned
B18	1 MAY 80	1 DEC 90	Abandoned
B22	1 AUG 81	1 MAR 83	Abandoned
B129	1 APR 83	1 NOV 94	Abandoned
B65	1 SEP 86	1 NOV 94	Abandoned
B54	1 MAY 87	1 NOV 94	Abandoned
B172	1 AUG 87	1 JUN 92	Abandoned
B145	1 JUL 88	1 JUL 95	Abandoned
B56	1 AUG 89	1 JUN 94	Abandoned
B190	1 SEP 89	1 JUN 98	Abandoned
B110	1 OCT 89	1 JAN 00	Abandoned
B165	1 FEB 90	1 JUN 94	Abandoned
B206	1 MAY 90	1 SEP 99	Abandoned
B167	1 NOV 91	1 JAN 96	Inactive
B152	1 MAY 94	1 APR 95	Abandoned
B169	1 JUN 94	1 JUL 95	Abandoned
B144	1 NOV 95	1 JUL 98	Abandoned
B175	1 SEP 96	1 SEP 98	Abandoned
B148	1 JAN 97	1 SEP 98	Abandoned
B157	1 AUG 97	1 JAN 00	Abandoned
B173	1 JAN 98	1 SEP 99	Abandoned
B210	1 JAN 98	1 MAR 04	Abandoned
B83	1 JUL 98	1 JAN 05	Abandoned
B155	1 DEC 98	1 JUN 00	Abandoned
B123	1 MAY 99	1 SEP 03	Abandoned
B156	1 JUL 99	1 JUN 04	Inactive
B140	1 FEB 00	1 DEC 00	Inactive
B178	1 MAY 00	1 MAY 03	Abandoned
B149	1 JUL 00	1 AUG 01	Abandoned
B24	1 JAN 01	1 AUG 07	Abandoned
B241	1 SEP 02	1 FEB 13	Active
B181	1 JUL 03	1 FEB 13	Active

6.3. Verification of the Flow Model

Verification of the fluid model is merely comparing the actual results with the simulated results. If the simulated results are close or even identical to the actual field results then the simulation is accepted as a true simulation. However, if the results of the simulation is not similar or somewhat different from the actual then the parameters used to create the simulation must be inspected. This verification process also called 'History Matching'. In history matching, production data of wells, total produced fluids for each phase, average reservoir pressure and original fluid phase in place can be used as a comparison parameter.

In this thesis, original gas in place in the reservoir, average pressure of the reservoir and total fluid productions were considered to be the parameters to match since the gas production of each well used as input for the simulation.

Approximately 40 different runs were conducted in this thesis in order to create an acceptable fluid model. The high number of simulation caused by different things such as lack of experience, lack of data and even the shortness of run times.

Lack of knowledge about the simulation software, ECLIPSE, caused some problems at first runs. Misplaced keywords, missing termination symbol (/) or using wrong keywords are the main issues in the beginning. Although these mistakes were considered weakness, they are the ones that taught the true way of using the ECLIPSE software.

After first runs and gathering some experience the second issue comes to the surface, lack of data. Despite the company provided so many data, some crucial ones are missing. During of the creation of fluid model, a working static reservoir model and a good fluid property model is needed. But the fluid property model is solely a result of a gas composition in which the temperature and pressure conditions of it is unknown. Also the conditions of the experimental data, which used in fluid property model, is not known either. Therefore for every inaccurate result of the simulation the petro physical properties used to generate the static reservoir model is subjected to change. Porosity and the permeability were the main area of focus for making the results similar. Even these data were represented truly at constructing the static reservoir model they were tweaked.

Besides porosity and permeability, the saturation function tables for each phase were also changed. Table 8 shows the finalized porosity and permeability distributions and Table 9 represents the finalized saturation functions.

Table 8. Finalized Values for Porosity and Permeability

Property	Minimum	Maximum	Mean	Standard Deviation
Permeability	10	20	15	3.5
Porosity	0.185	0.325	0.26	0.03

Table 9. Finalized Saturation Function for each phase

Water		
Saturation (S_w)	**Relative Permeability (kr_w)**	**Capillary Pressure**
0.24	0	0
0.6	0.8	0
1	1	0
Gas		
Saturation (S_g)	**Relative Permeability (kr_g)**	**Capillary Pressure**
0	0	0
0.35	0	0
0.46	0.04	0
0.64	0.15	0
0.76	0.45	0
Oil		
Saturaion (S_o)	**Relative Permability (kr_o) 2-Phase**	**Relative Permability (kr_o) 3-Phase**
0	0	0
0.3	0	0
0.76	0.2	0.2

As can be seen in Table 8 the permeability values are different from the core data analysis. Although this values are not considered as true values they are making the fluid model results closer to the actual data.

In Table 9 saturation values for each phase and corresponding relative permeabilities were shown. These values are adjusted to simulate condensate blockage effect on the reservoir. Since when the condensate (oil) saturation reach to the 0.3, due to the irreducible water saturation is being 0.24, only 0.46 of the pore volumes are filled with gas and the corresponding gas relative permeability is 0.04 which is very low compared to 0.45 at the initial.

The last reason for the high number of runs takes place in this thesis is the short time needed for a run to finalize. At first runs it duration of them was around 8 to 8.30 minutes which was very good and this value was lowered to 2 minutes by simply making Zone 1 and Zone 3 in active along with the grid blocks other than the Block 2.

This short duration leads to the high number of simulation runs can be conducted by changing very small things such as changing relative permeability of gas by 0.01.

After all of the runs performed, the base case scenario where the simulated results within the acceptable range of actual data recorded in the field is created. In Table 10 comparison of various results between simulated reservoir and the actual reservoir is shown. Also Figures 26 and 27 shows the comparison of production rate of the reservoir for oil and gas phases between simulated and actual results.

Table 10. Comparison between Simulated and Actual Results

Variables	Simulated Results[1]	Actual Results[2]	Ratio
Average Reservoir Pressure (psia)	4009	2425	1.65
Original Gas in Place (10^{11} ft^3)	9.15	9.95	0.92
Cumulative Gas Production (10^{11} ft^3)	4.6	4.74	0.97
Cumulative Condensate Production (MMstb)	17.09	7.58	2.25

1 February, 2013
2 September, 2013

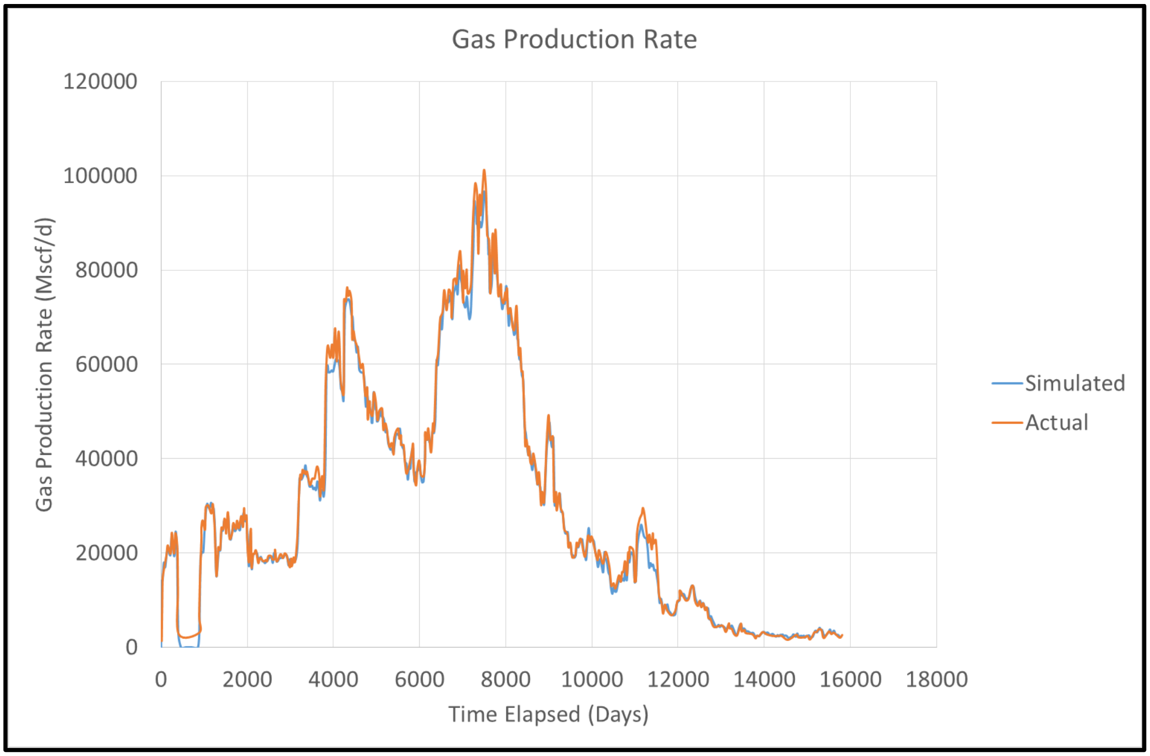

Figure 26. Gas Production Rate Comparison

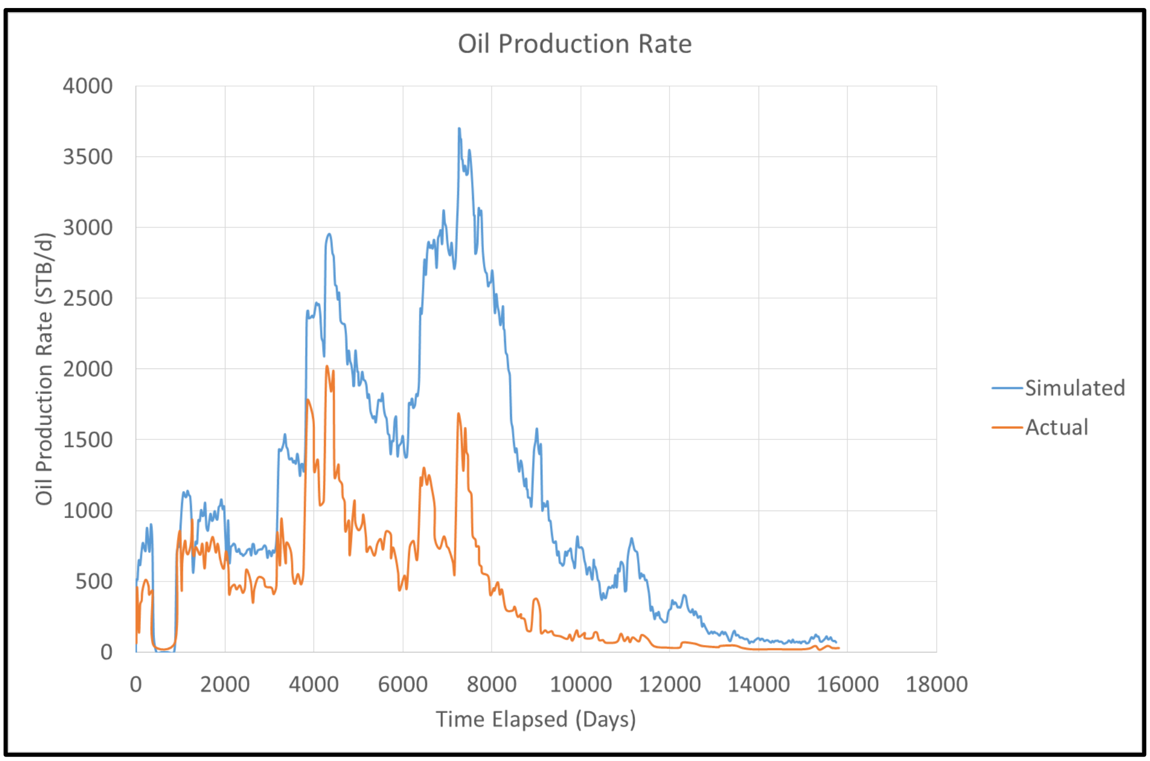

Figure 27. Oil Production Rate Comparison

As can be seen in Table 10 some properties are similar to each other in both simulated and actual results. These are Original gas in place (OGIP) and Cumulative gas production (G_p). Likewise Table 10, Figure 26 is showing the consistency between simulated and actual gas production rates. Although this result is expected due to gas production rate being an input for simulation it shows that the tweaked data for permeability and saturation are in acceptable range. Because the permeability or the saturation is not in acceptable range the produced volumes might not be achieved by the wells in simulation.

Withal other than the considered properties, other properties were remotely different. The 1.65 ratio of simulated and actual results of P_{av} is caused by the actual data were given by the company measured at bottom hole. They are well specific pressures where the average reservoir pressure is not calculated as a result of production rather simply recordings of downhole pressure probes. These data were recording while the wells were active and they are producing. However, since the trends for both simulated and given pressure decline is matching it is understood that the simulated pressure decrease can be accepted.

The difference in cumulative condensate production however is caused by the R_v values defined for the ECLIPSE. Since R_v is the ratio of vaporized oil in Gas, condensate production is in relation with gas production proportional to R_v. Assuming the fluid property model created by PVTi software is true, considering there is nothing to compared with, the R_v values created by it are also true. However the difference in oil production values show us that our R_v values are overestimated and it gives higher oil production than expected. In addition to Table 10, Figure 27 is also showing that the oil production rates in simulation is higher than expected yet the trend of the rates is somewhat identical. This points out the fact that R_v values are higher than it should be.

With this fact at hand one should try to better the fluid property model but in this thesis there is nothing to make fluid property model better, for the sake of continuation of this thesis work the data submitted by the company is chosen to be a starting point and the history matching part of the simulation assumed to be conducted truly by considering the probability to create a true fluid model of the operated field is very low in accordance to data at hand.

CHAPTER 7

RESULTS AND DISCUSSION

Following the verification of fluid model production forecasting should be done in order to find out the optimal production rates and strategies for the reservoir towards maintaining reservoir pressure higher than the dew point pressure to prevent the formation of precious condensate within the reservoir section. To achieve this firstly optimal rate input for production should be analyzed and used it with different production strategies. The main boundaries for assessing production strategies are

- There will be no drilling activity in the field,
- Production will only be done by the two active wells,
- Base case scenario is the accepted fluid model which starts in 1970 and ends in February,2013 all production strategies cover the base case scenario and aims to produce 50 more years in the reservoir,
- The only prevention mechanism for the condensate blockage is maintaining reservoir pressure high, rather than using chemicals and other remediation techniques used in condensate blockage.

The steps for optimizing the production and maintaining pressure are as follows;

- Reservoir extremes analysis and finding optimal production mechanism
- Finding optimal injection strategies to prevent pressure decline in the reservoir

7.1. Production Strategies Estimation

Extreme conditions for reservoir is necessary to find out, to create an optimal production strategy. The main reason for this is to figure out the logical control mechanism for production and limitations of the field. Regarding to this, two different control mechanism are suggested with different values. First one is to limit wells production capacity with respect to flowing bottom-hole pressure and second one is to keeping gas production at a constant rate. Three different cases were created to see the effect of different flowing bottom-hole pressures and two for constant gas rate. Table 11 shows the parameters for different reservoir extremes analysis scenarios.

Table 11. Control parameters for different scenarios

Scenario	Well Name	Pressure (psia)	Flow Rate (Mscf/d)
Base Case	B181	3921	610
	B241	3838	1705
Case #1	B181	1470	-
	B241	1470	-
Case #2	B181	2940	-
	B241	2940	-
Case #3	B181	3675	-
	B241	3675	-
Case #4	B181	-	1375
	B241	-	3160
Case #5	B181	-	610
	B241	-	1700

As can be seen in Table 10, Base case scenario is the accepted fluid model where the pressure and flow rate data are at the end of February, 2013. Following cases were created for next 50 years and the values shown in Table 10 were kept constant to find out limitations of the reservoir. Results for these scenarios can be seen in Figures 28 – 32.

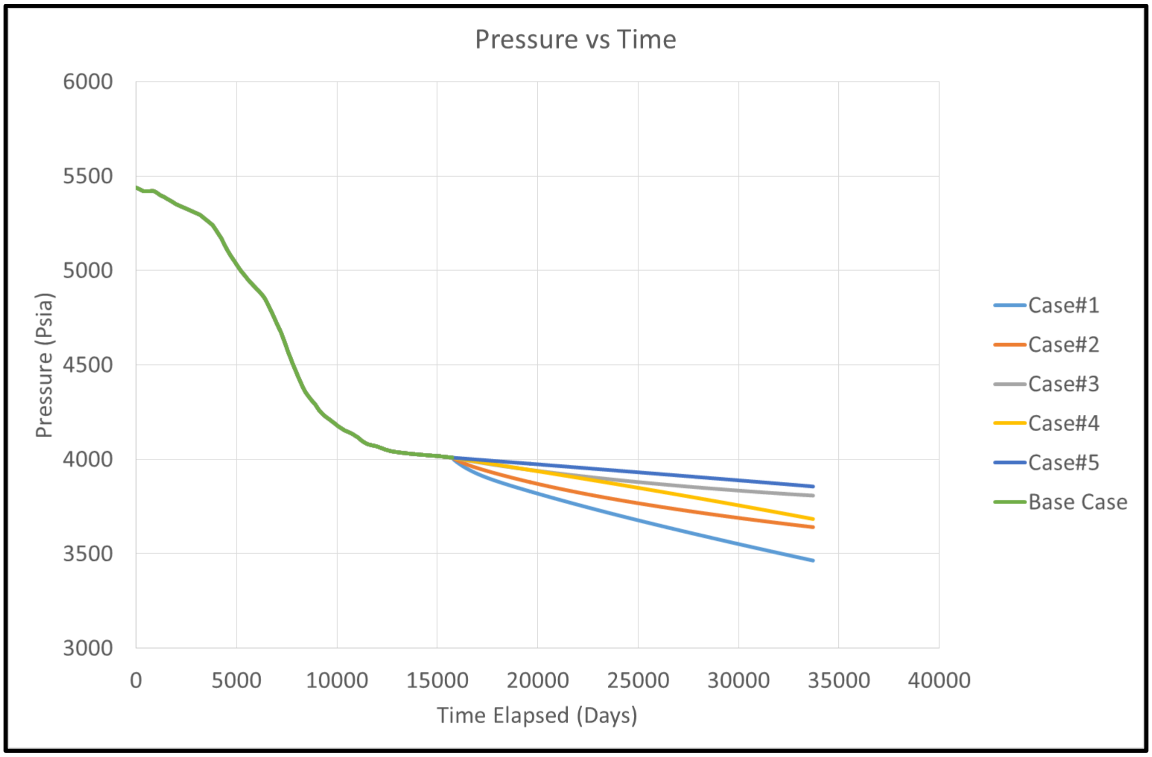

Figure 28. Pressure vs Time Graph for Different Scenarios

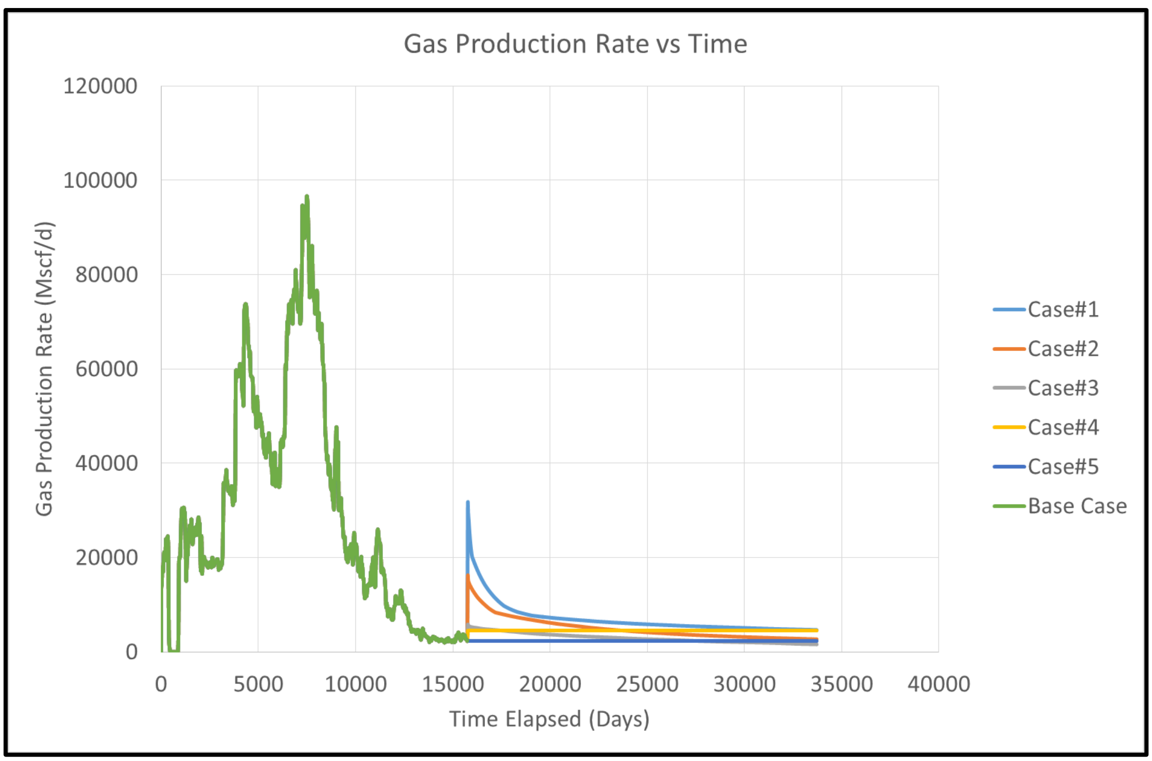

Figure 29. Gas Production Rate vs Time Graph for Different Scenarios

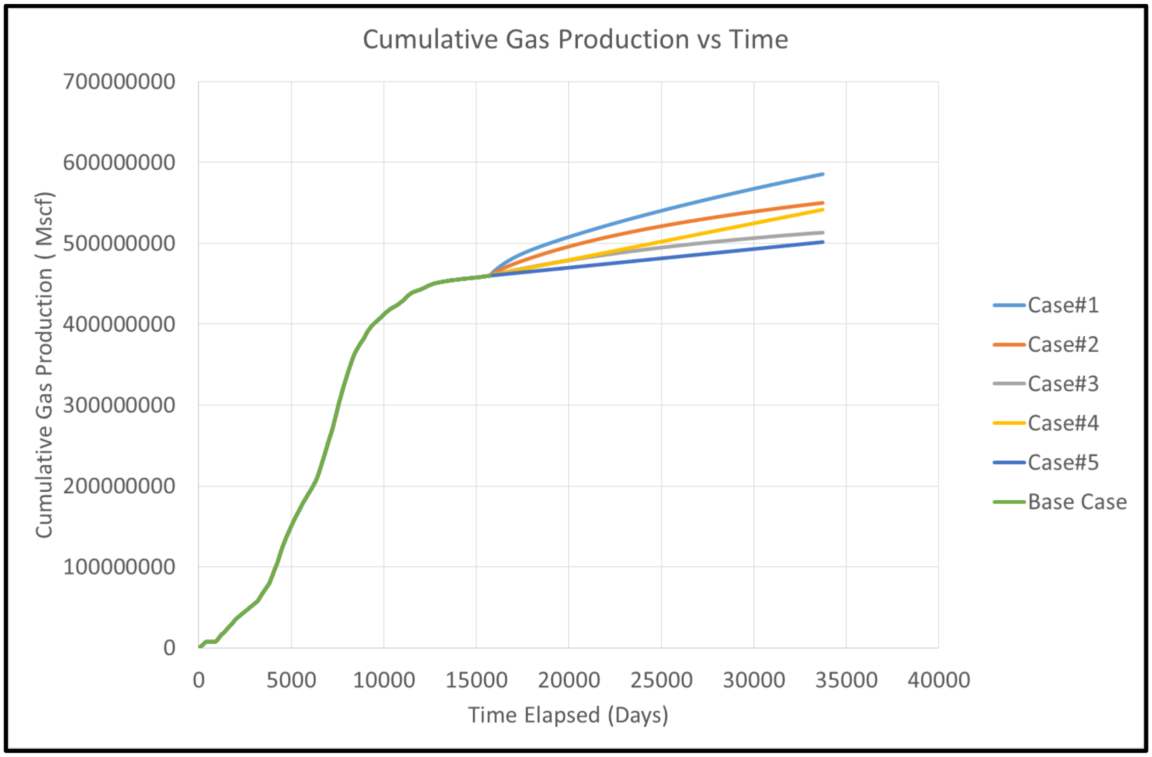

Figure 30. Cumulative Gas Production vs Time Graph for Different Scenarios

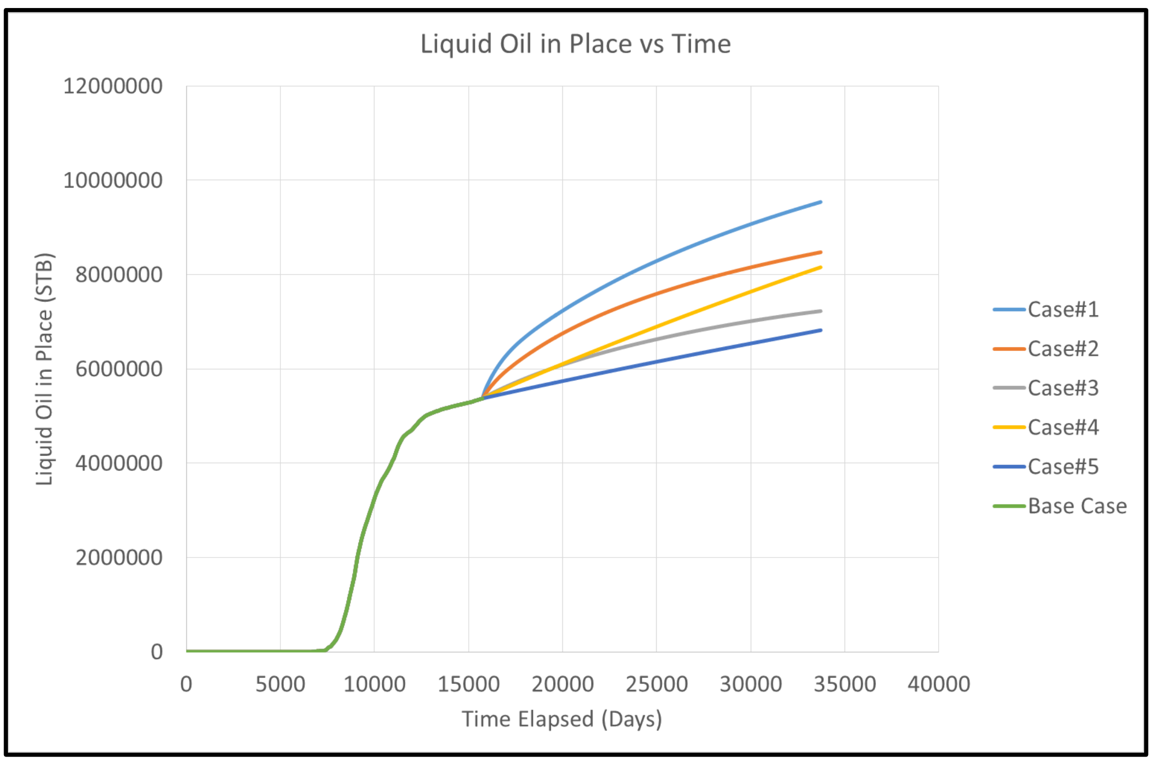

Figure 31. Liquid Oil in Place vs Time Graph for Different Scenarios

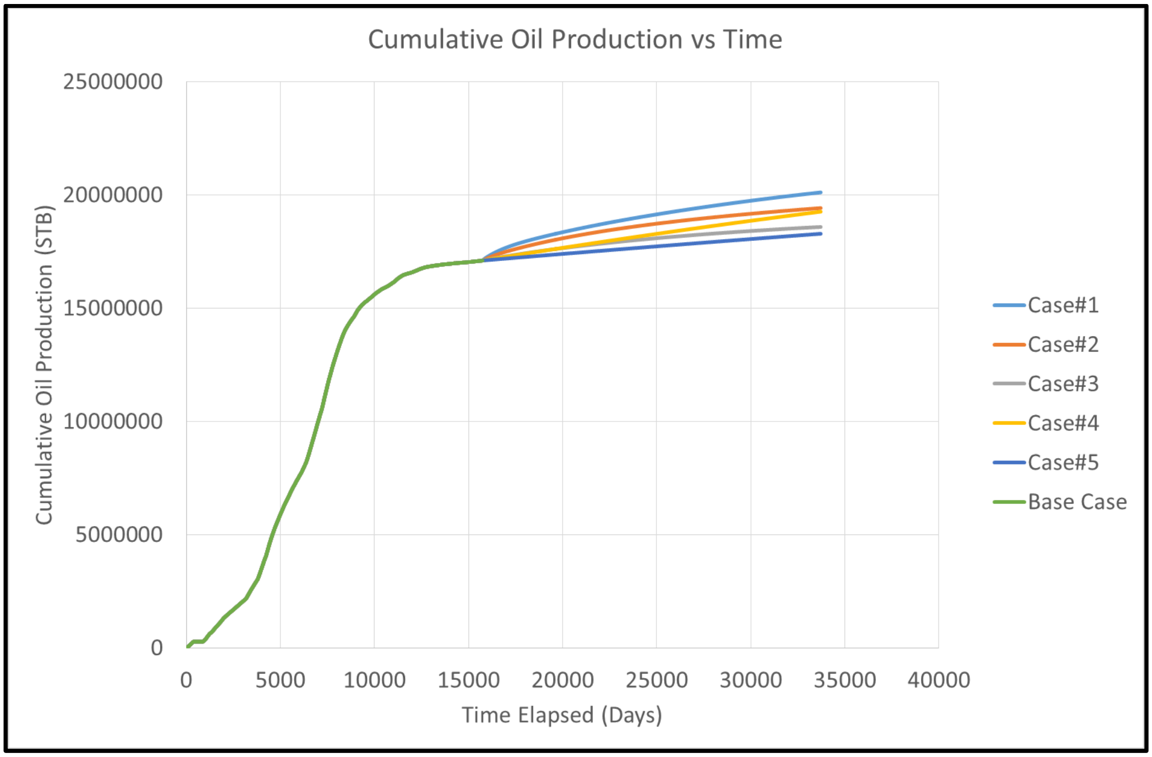

Figure 32. Cumulative Oil Production vs Time Graph for Different Scenarios

Inspecting Figures 28 – 32 one could understand the optimal production mechanism for the future. In this thesis Case#4 which is maximum production rate seen in wells are chosen as future production scenario. This is caused by its lower pressure drop rate and somewhat average production values.

Case#1 is not chosen to be future production scenario because in this case average pressure of the reservoir decreased rapidly and reached up to 3450 psia while the nearest case which is Case#2 is dropped only 3650 psia. In addition to the pressure, although Case#1 is the one with the highest Cumulative gas and cumulative condensate production, the high numbers of condensate drop-out occur in the reservoir making this case is not so good at all since the main aim in this thesis is to produce economically precious condensate in the surface conditions. Then again inspecting Figure 29 shows that sharp decline in bottom-hole pressure followed by sharp increase in gas rate however because of the condensate blockage around the wellbore, wells cannot maintain the high amount of gas production.

The reasoning behind Case#2 is similar, the gain caused by the sharp decline in pressure does not achieve much since the condensate blockage again occurs in the wellbore area.

Case#3 and Case#5 shows similar results with each other. Although in this scenarios condensate blockage around the wellbore is neglectable, results in productions shows that with this conditions reservoir is not working in optimal rate since reservoir could achieve higher production data without compromising itself.

Thus these results leads to the Case#4 is being the favorable one. Since it can reach nearly the same cumulative gas and condensate production with Case#2 while there is no condensate blockage around wellbore occur and result with lower condensate drop-out in the reservoir and higher average pressure in the reservoir after 50 years of production is considering a good starting point for future production strategies.

7.2. Injection Strategies Estimation

Following of future production control mechanism, this thesis focus on improving the conditions of the reservoir and finding a sustainable production strategy for this reservoir by keeping the pressure stable. In this thesis, pressure maintenance is supplied by injection of water/gas to the reservoir. In following parts of this chapter, different control mechanism for injection strategies will be investigated. In order to find out the optimal injection strategies, which will leads to the sustainable reservoir management, seven different scenarios were conducted. Table 11 shows the summary of parameters for different runs.

Table 12. Summary of Parameters for each Injection Scenario

Scenario	Preferred Production Case	Preferred Injection Phase	Control Mechanism for Injection	Value of Control Mechanism	Date Injection Starts
Case#6	Case#4	Water	BHP	4900	MAR 2013
Case#7	Case#4	Water	Flow Rate	1500	JAN 2022
Case#8	Case#4	Water	Flow Rate	1000	MAR 2013
Case#9	Case#4	Gas	BHP	4900	MAR 2013
Case#10	Case#4	Gas	Flow Rate	900	MAR 2013
Case#11	Case#4	Water	Flow Rate	1000	MAR 2013
		Gas	Flow Rate	900	MAR 2013

As can be seen in Table 12, injection strategies could be categorized according to preferred injection phase;

- Water Injection Strategies
- Gas Injection Strategies
- Combination Injection Strategies

7.2.1. Water Injection Scenarios

Cases #6 to #8 can be considered as water injection scenarios. These scenarios differ from each other by their injection control mechanism, or their starting date of injection. Same wells were used in each one of them and they were chosen from the previously abandoned wells in the field. Locations are the essential factor to choose the wells as water injectors. Closer to the producing well locations and being in the flanks of the reservoir are the major points in selections. Figure 33 shows the locations of the producing and water injection wells.

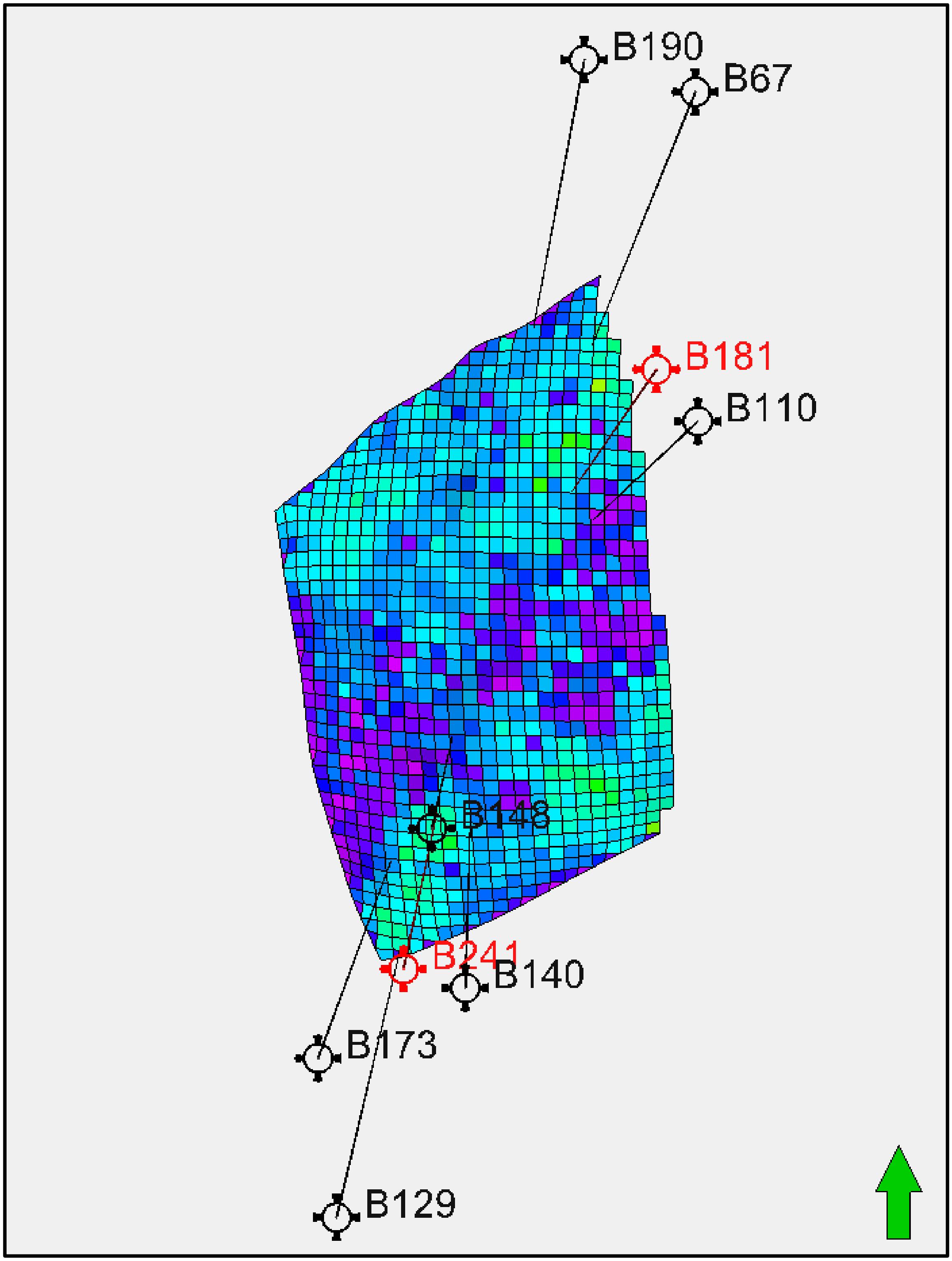

Figure 33. Name and locations of the wells used in Water injection (Red = Production, Black = Injection)

In Case#6 bottom-hole pressure is chosen as control mechanism and its set to 4900 psia which is average initial pressure for each well. The reason behind for making the bottom-hole pressure so high is to see the extremes of the reservoir and also find out the extremes are whether achievable or not.

In Case#7 water injection rate is chosen as control mechanism and it adjusted as 1500 stb/d for each well. In this scenario also the starting point for the injection is taken as January 2022 as the liquid in place between Case#3 and Case#4 starts to differentiate at early times of 2022. It is thought that since producing for 9 years with bottom-hole controlled case (Case#3) and the flow-rate controlled case (Case#4) is acting as same in terms of liquid in place an extra pressure supply for Case#4 at that time could prolong the liquid in place similarities between two cases while making Case#4 have higher pressure and higher production rates along with the money spend on injection water will decrease.

In Case#8 again the water injection rate is control mechanism however this time the water injection starts at March, 2013 while the rate is decreased to 1000 stb/d for each well. This is because the rate 1500 stb/d/w is similar to the 4900 psia BHP case and it’s taught as extreme since it is hard to achieve.

Case#7 of water injection is controlled by the water injection rate is also neglected due to fact that the bottom-hole pressure needed to inject that much of water exceeds the 4900 psia. It can be understood by analyzing the Figure 39. The bottom-hole controlled water injection case (Case#6) shows a declining trend towards to end of simulation and even it drops below 1500 stb/d/well rate at around 21000th day. Therefore for water injection scenario Case#8 chosen to be the applicable and good strategy since the pressure of the reservoir is above the dew point pressure at the end of the 50 year of production/injection and due to the lower injection rate the water productions is the lowest one. By considering pressure and water production data, water injection rate could be lowered even more. However the increasing trend of Liquid Oil in Place data towards the end of simulation shows that water injection cannot be the only solution for this thesis’s problem. It is thought that the increase in later part of the Liquid Oil in Place graph (Figure 35) can be caused the rate of water injection is not enough to fill the volumes around the wellbore by the low mobility and expansion of water and additionally with the low permeability of the reservoir.

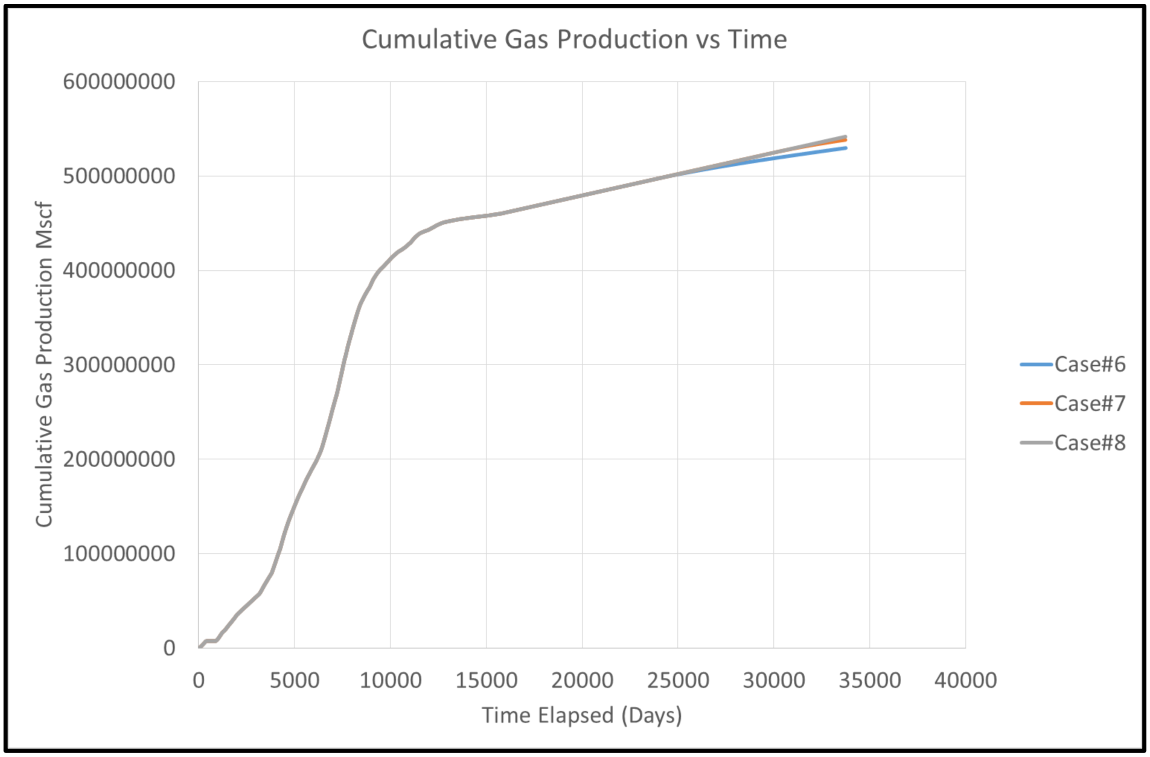

Figure 34. Cumulative Gas Production vs Time Graph for Water Injection Cases

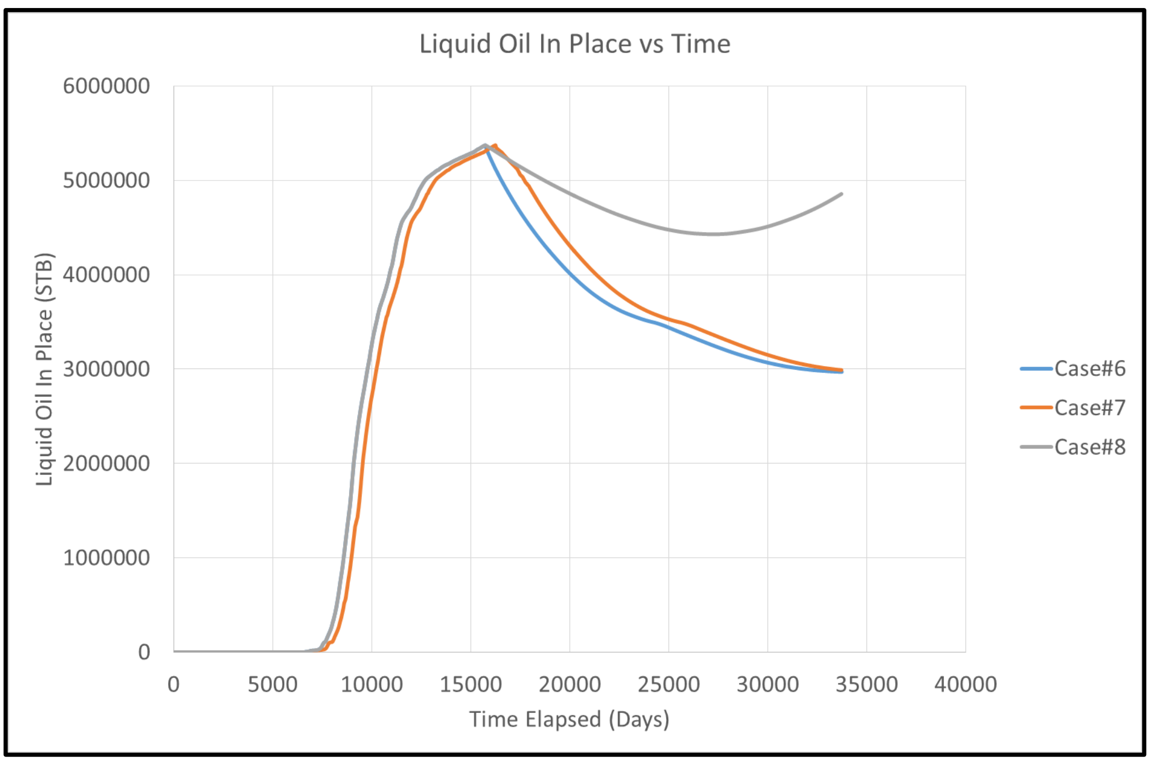

Figure 35. Liquid Oil in Place vs Time Graph for Water Injection Cases

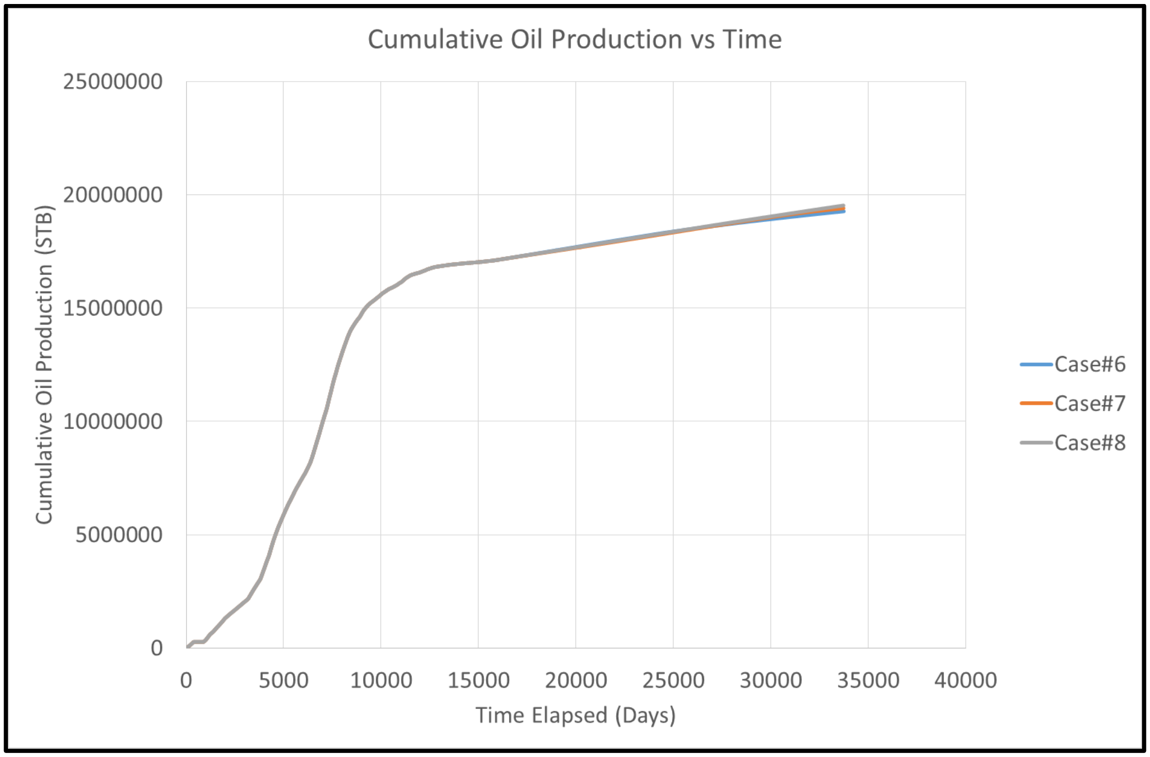

Figure 36. Cumulative Oil Production vs Time Graph for Water Injection Cases

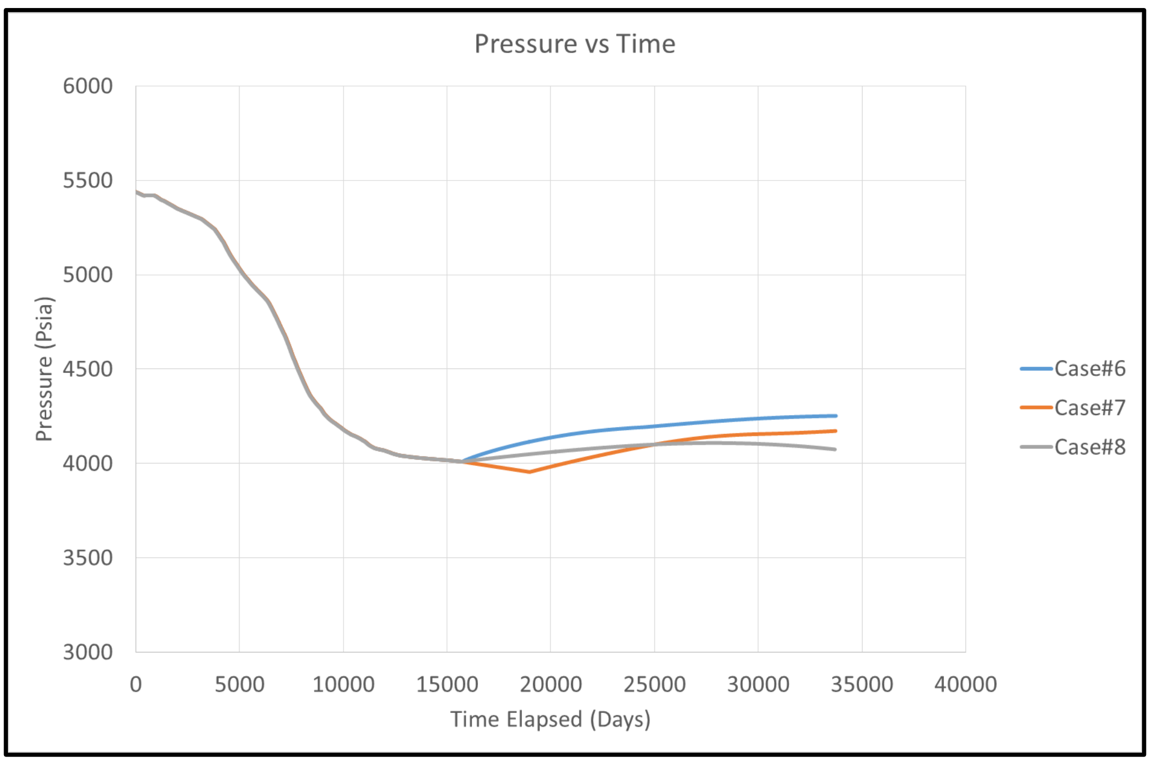

Figure 37. Pressure vs Time Graph for Water Injection Cases

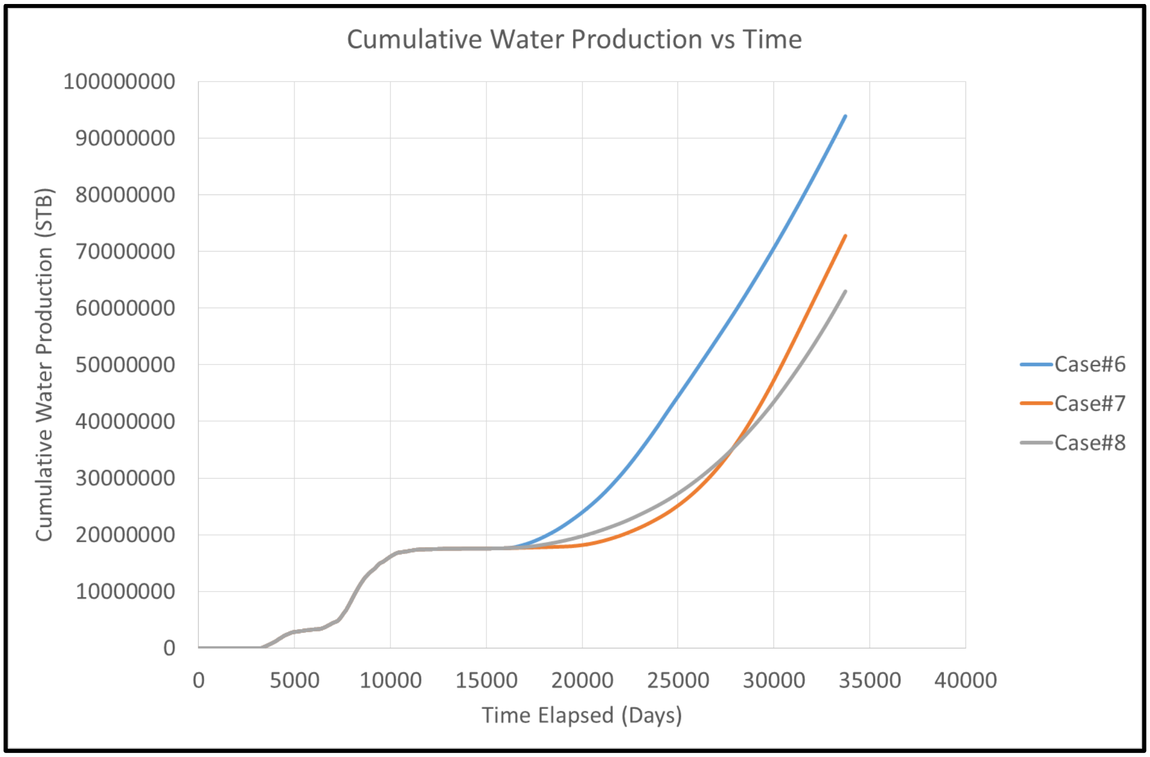

Figure 38. Cumulative Water Production vs Time Graph for Water Injection Cases

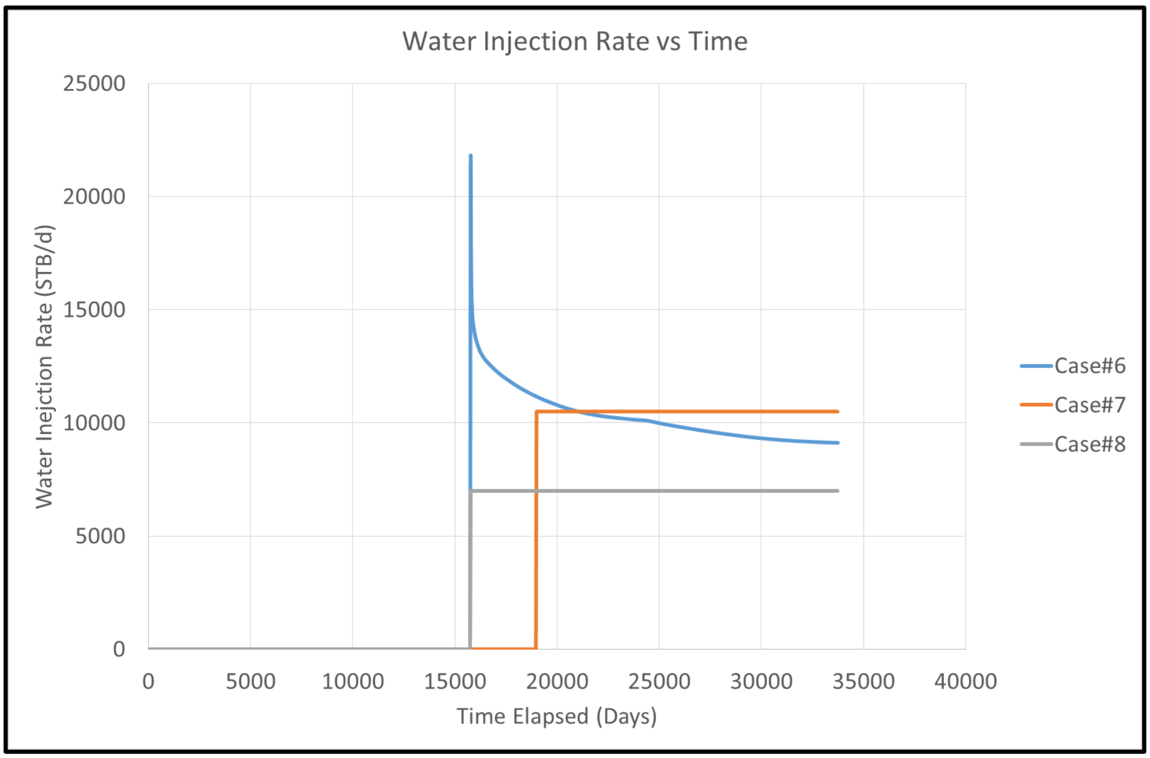

Figure 39. Water Injection Rate vs Time Graph for Water Injection Cases

7.2.2. Gas Injection Strategies.

As specified earlier cases #9 and #10 are considered as Gas injection strategies. In this cases 4 wells were specified according to their locations in terms of geological structure of the reservoir and the distance to the producing wells. Since the reservoir is in anticlinal shape the middle of the reservoir area coincides with the tip of the anticlinal structure. As gravitational forces are concerned the gas collected at the top of the reservoir and it makes the tip of anticlinal structure is a good place to produce or inject gas to the reservoir. Three of the chosen 4 wells are obeying this rule and the last well is chosen closer to the production well 'B241' and the well is at the local high zone. Figure 40 shows the location of the producing and gas injection wells.

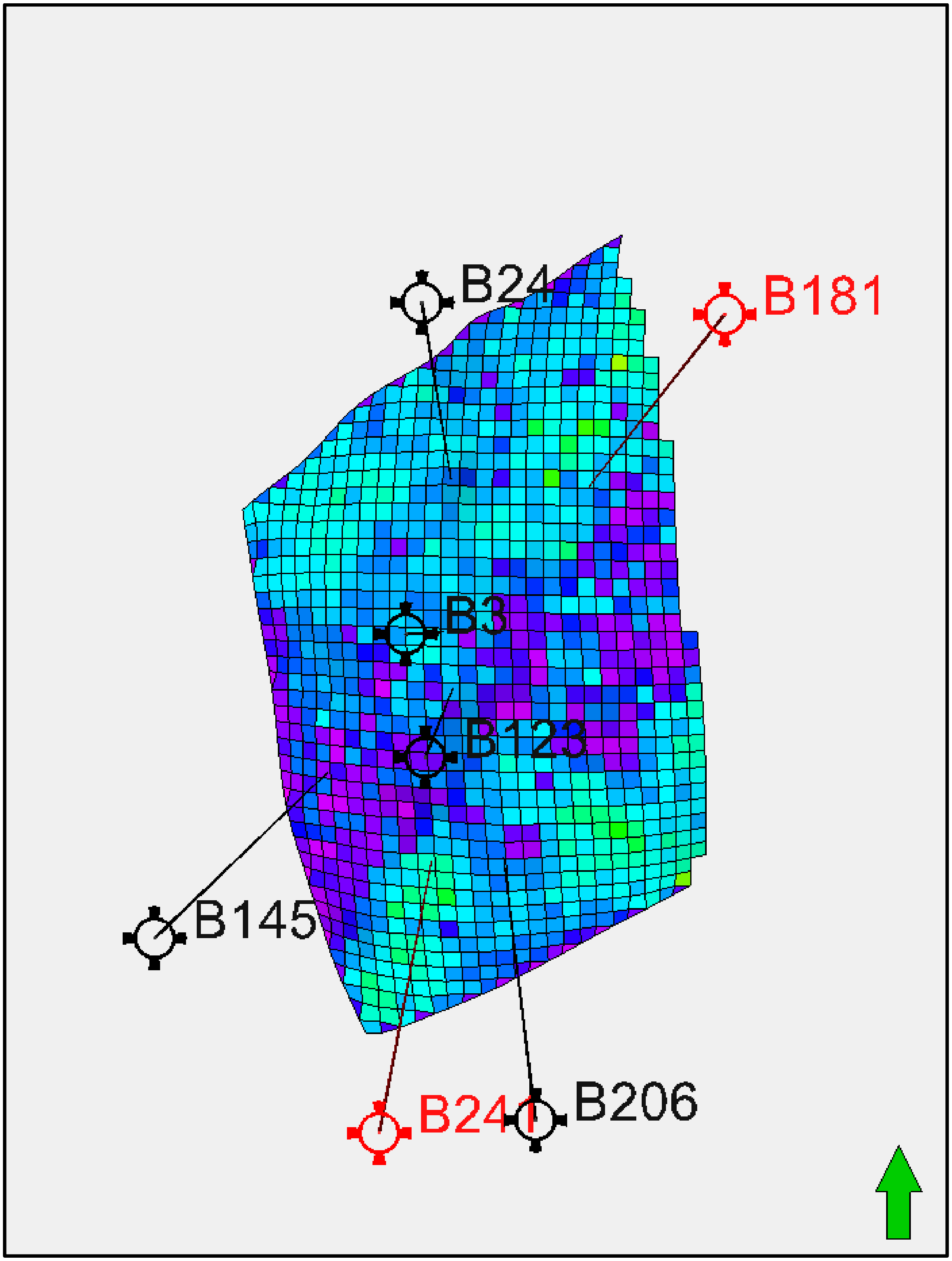

Figure 40. Name and locations of the wells used in Gas injection (Red = Production, Black = Injection)

In order to find out the optimal gas injection strategies, two different scenarios were created. Since the gas injection is limited by the economic factors the first scenario is designed to understand the maximum gas injection rate needed in this reservoir. In the second gas injection scenario nearly all of the gas that is produced will be injected back to the reservoir after separating the condensate from the gas.

Similar to Case#5 of the water injection scenario, Case#9 all wells are set to inject gas to satisfy the bottom-hole pressure condition 4900 psia. This is conducted to see the extreme condition for the reservoir again.

In Case#10 the control mechanism for injection change it to gas rate. In this case it is thought that it is essential for this reservoir to produce condensate rather produce gas. Therefore to keep the pressure high and limiting condensate drop out produced gas will injected to the reservoir after the separation from the condensate. The gas production rate is at surface is 4535 Mscf/d and with total of 5 injection wells the rate is set to 900 Mscf/d therefore injecting 4500 of 4535 Mscf/d.

As can be seen from the Figures 42 and 44 the bottom-hole pressure controlled case in gas result with very high pressures and lowering the liquid oil in place ratio however the amount of gas needed shown in Figures 41 suggests this option is not possible to conduct (Case#9).

Figure 42 shows that Case#10 is a viable option for this reservoir since it lowers the liquid oil ratio in the reservoir which means that the condensated liquid were again vaporized and gives the ability to produce more condensate from the reservoir. In addition to Figure 42, in Figure 44 the pressure of the reservoir remains constant since the reservoir fluid volume kept nearly constant throughout the production/injection process.

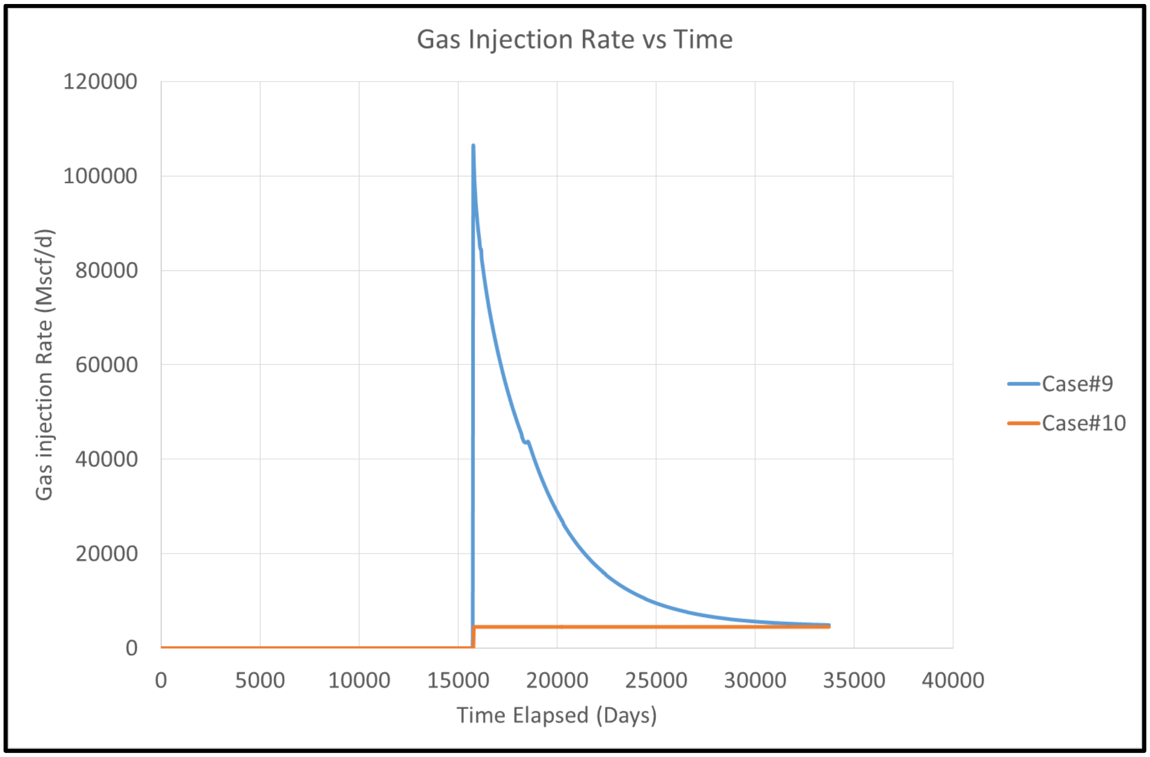

Figure 41. Gas Injection Rate vs Time Graph for Gas Injection Cases

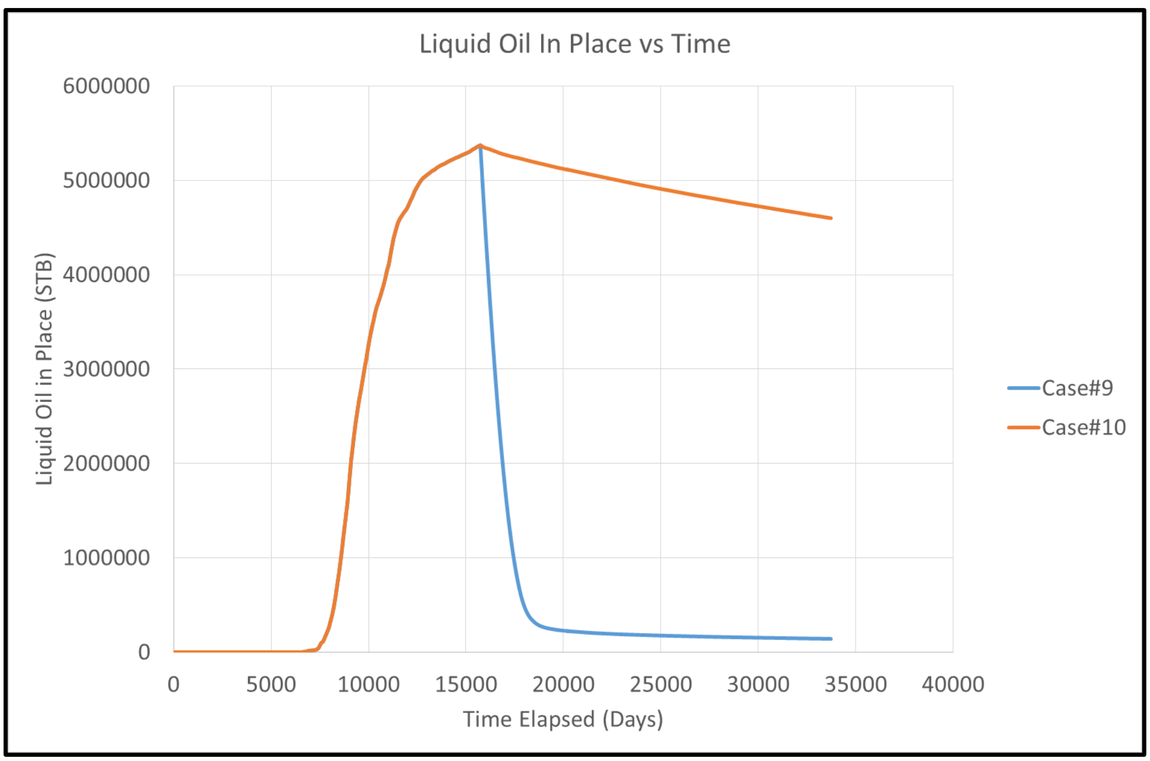

Figure 42. Liquid Oil in Place vs Time Graph for Gas Injection Cases

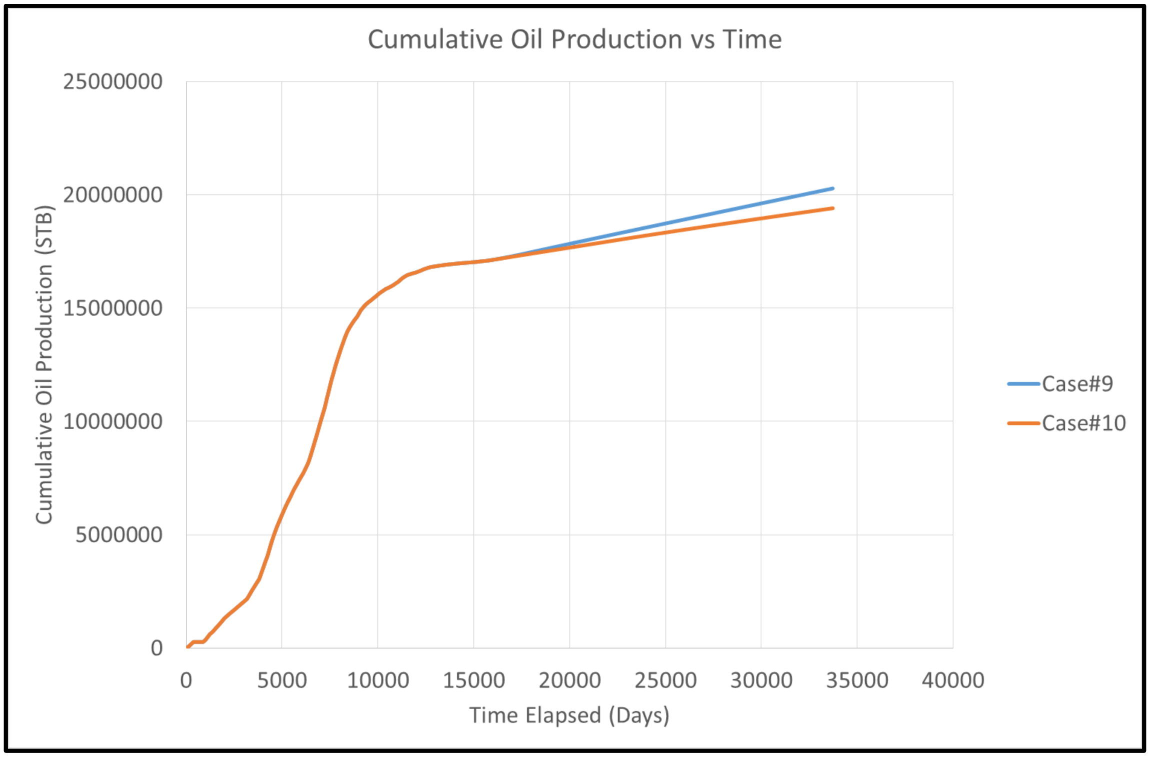

Figure 43. Cumulative Oil Production vs Time Graph for Gas Injection Cases

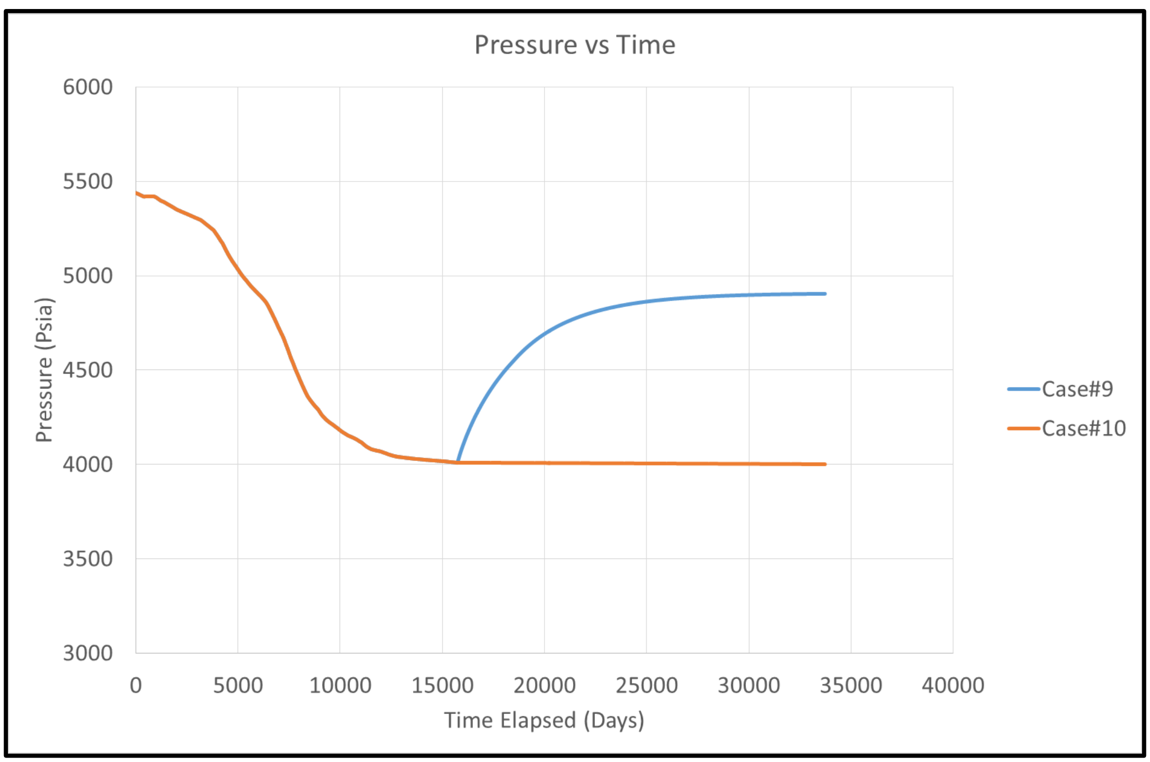

Figure 44. Pressure vs Time Graph for Gas Injection Cases

7.2.3. Combination Injection

Due to the fact that producing only gas condensate in a gas reservoir is not an acceptable option the gas injection in this reservoir should be coupled with water injection since the water injection is not enough to optimizing the production of this reservoir solely.

Both water and gas injection has its advantages and disadvantages therefore combination of both could be very effective since they can nullify other ones disadvantages. Such as high amount of water injection can change the reservoir fluid property but lowering the injected amount is not acceptable since the pressure in the reservoir will decrease much faster. By combining water injection with gas injection, rates of water injection could be lowered due to gas injection can make up the pressure decrease in reservoir. By considering this and having a two good cases that need improvements Case#11 was created as a combination of both Case#8 and Case#10 and this case solve the problems of both cases. All of the wells that were used in gas and water injection were used in this case and it can be seen in Figure 45.

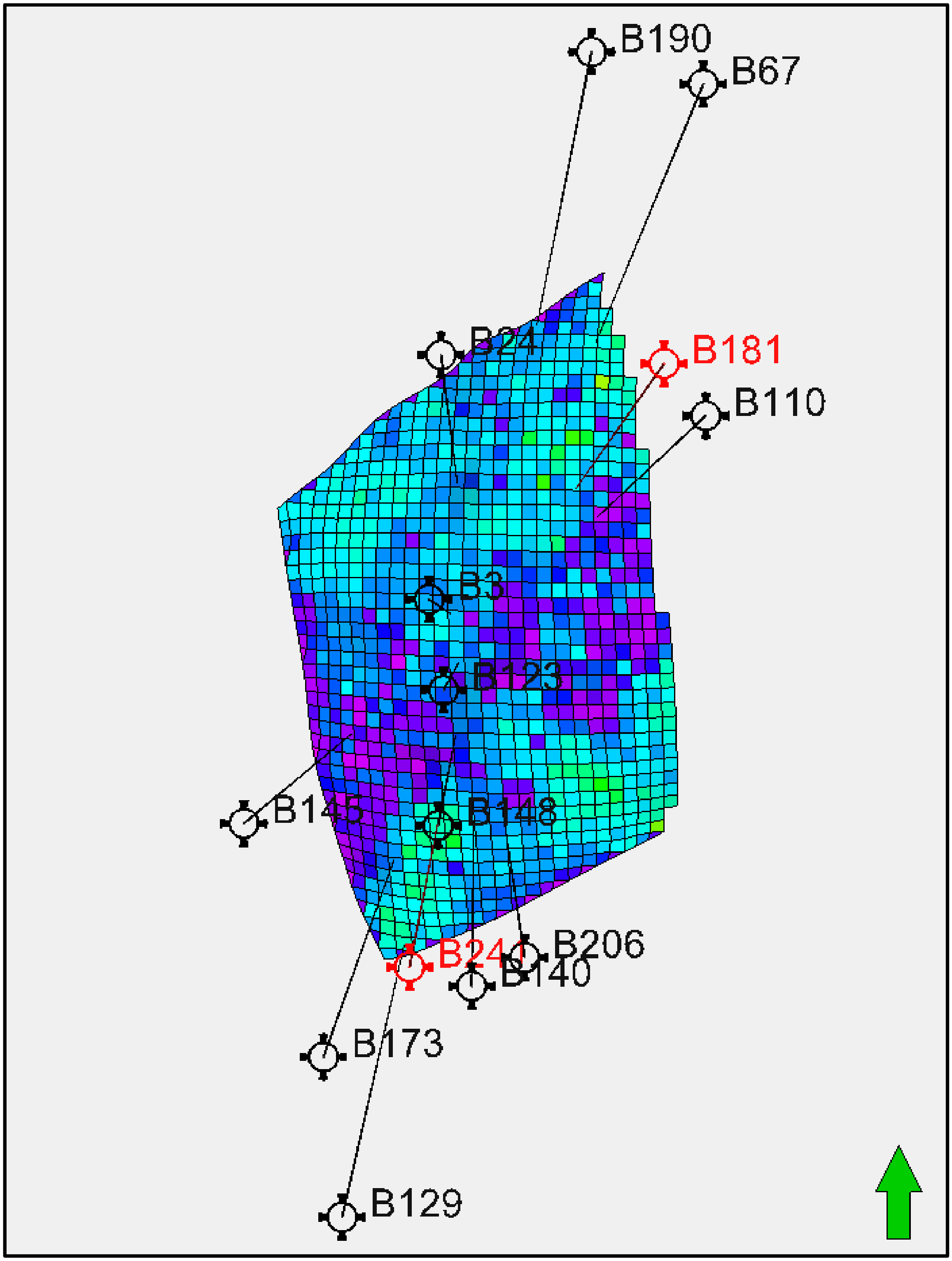

Figure 45. Names and locations for all wells used in combination injection (Red = Production, Black = Injection)

Inspecting the Figure 47 shows that the injection strategies are working higher than the expected since the pressure of the reservoir increase continuously. The reason for this increase is that the injection rates exceeds the production rate which means the reservoir could produce more than the current case while does not decreasing the pressure which could easily solve the problem of not selling of the producing gas.

Figure 46 on the other hand is showing that the implementing the gas injection with the water give better results at the latter part of the simulation since the gas mobility and expansion is greater than the waters gas can fill up the pore volume spaces that created near the producing wellbores.

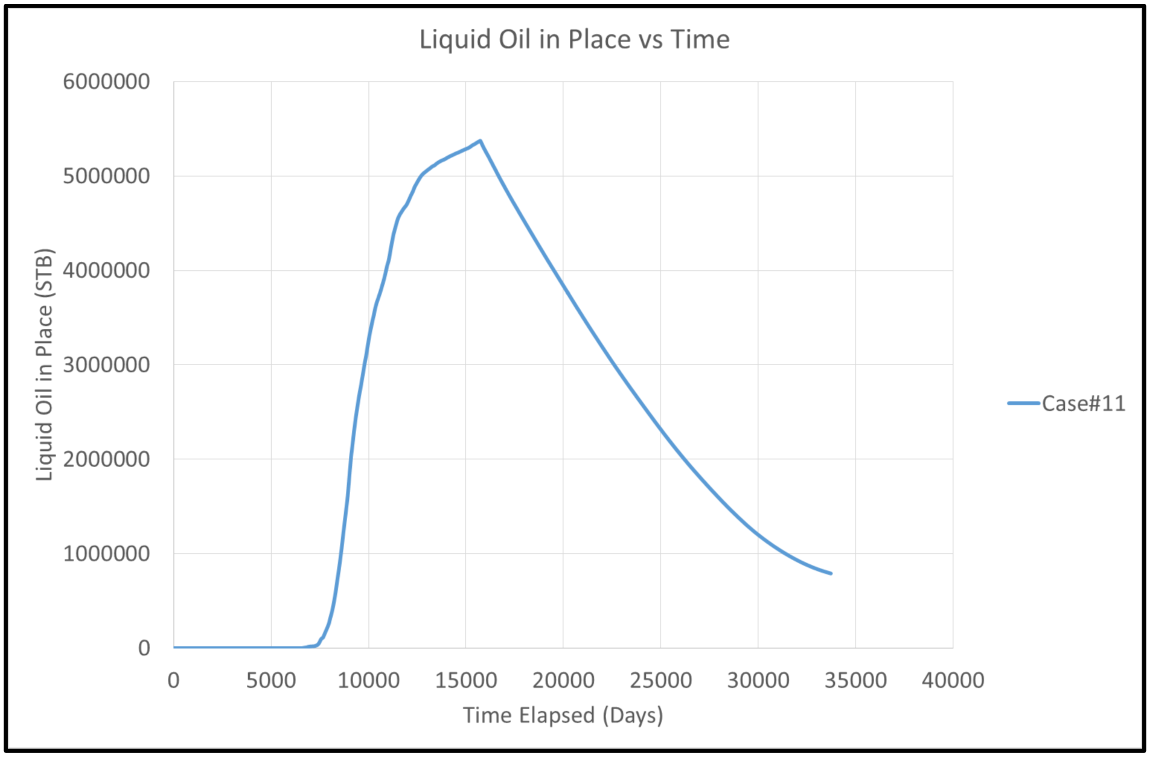

Figure 46. Liquid Oil in Place vs Time Graph for Case#11

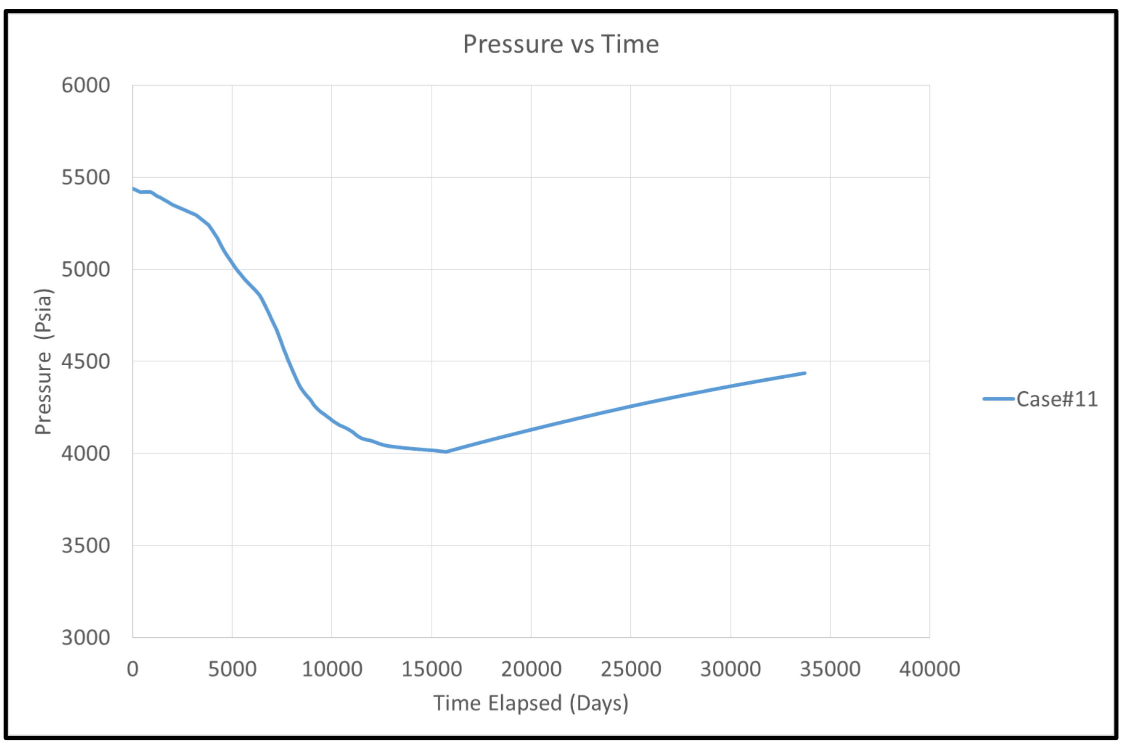

Figure 47. Pressure vs Time Graph for Case#11

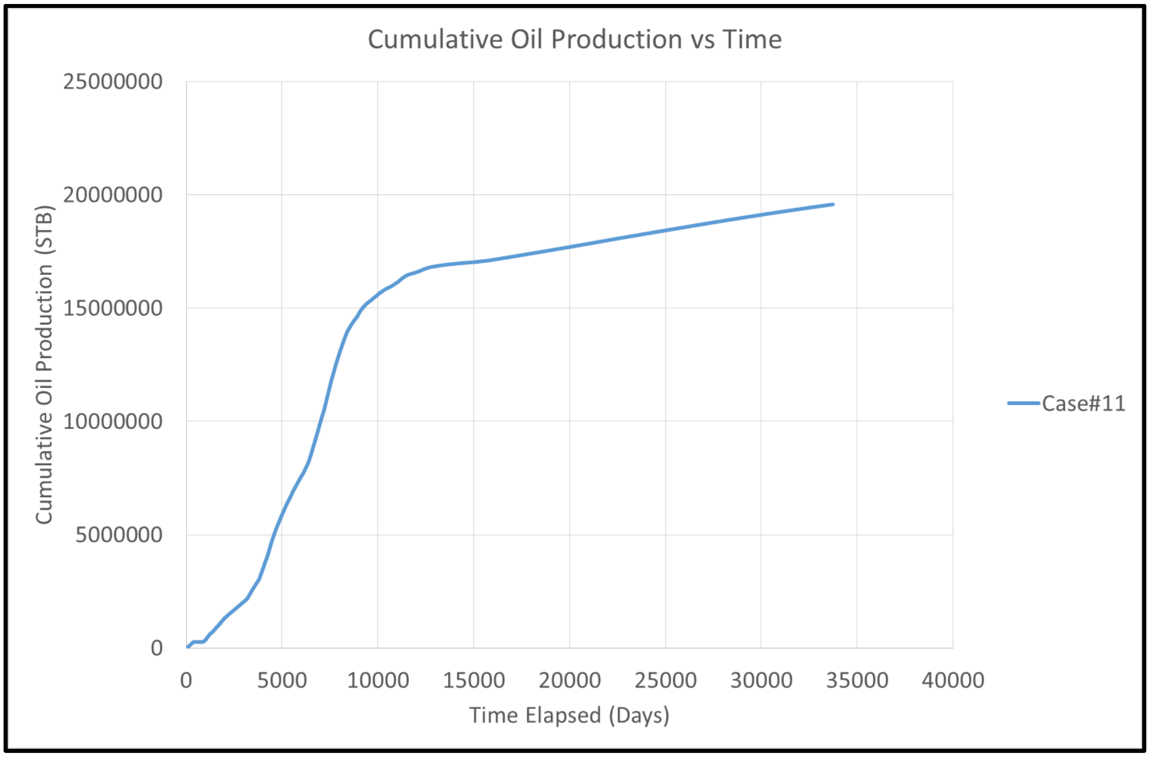

Figure 48. Cumulative Oil Production vs Time Graph for Case#11

After seeing Case#11 is a good starting point for future production strategies, Case#12 is generated by changing the constant gas flowrate at production to constant bottom-hole pressure at 3675 psia. Figures 49 - 50 show the comparison between Case#11 and Case#12 in terms of reservoir pressure, producing gas flowrate and liquid oil in place.

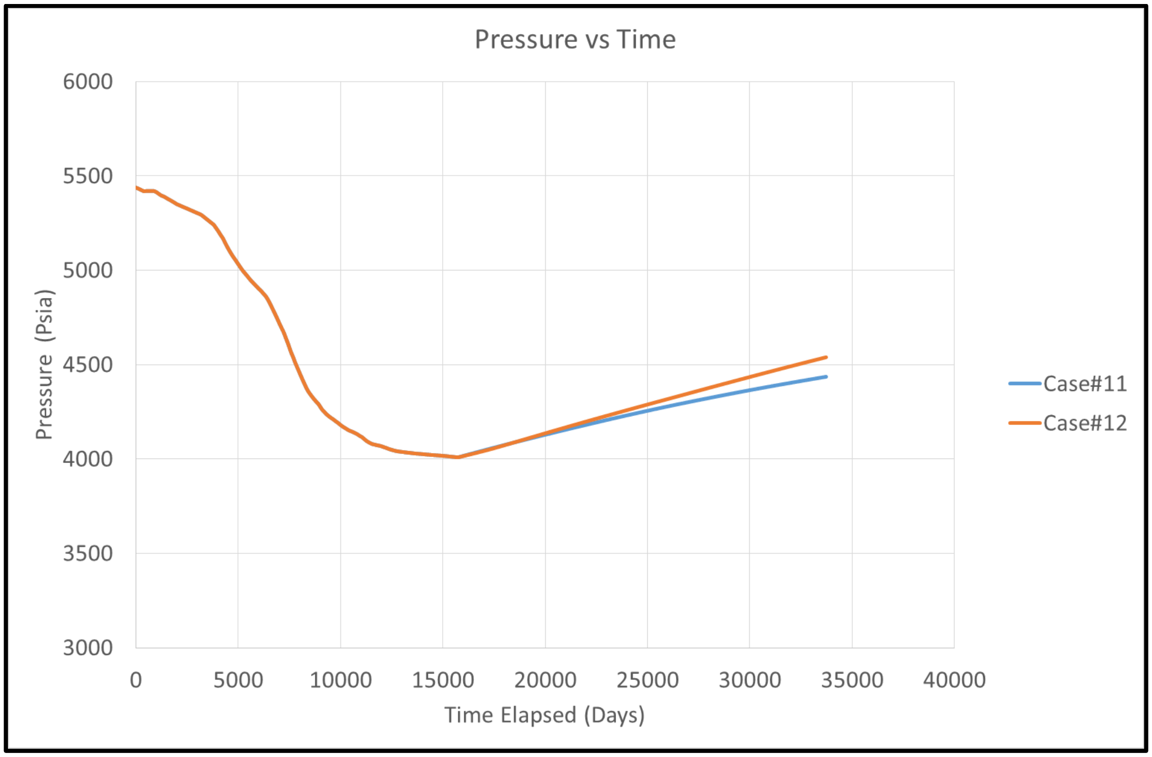

Figure 49. Pressure vs Time Graph for Combination Injection Cases

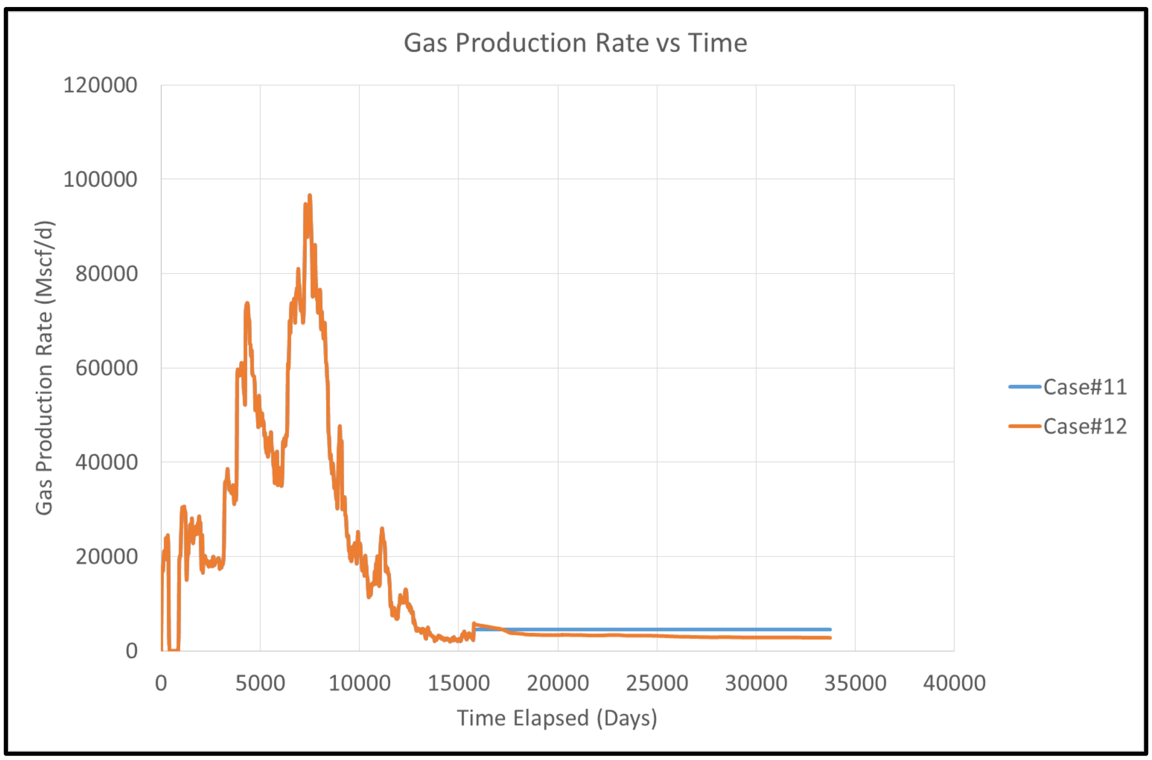

Figure 50. Gas Production Rate vs Time Graph for Combination Injection Cases

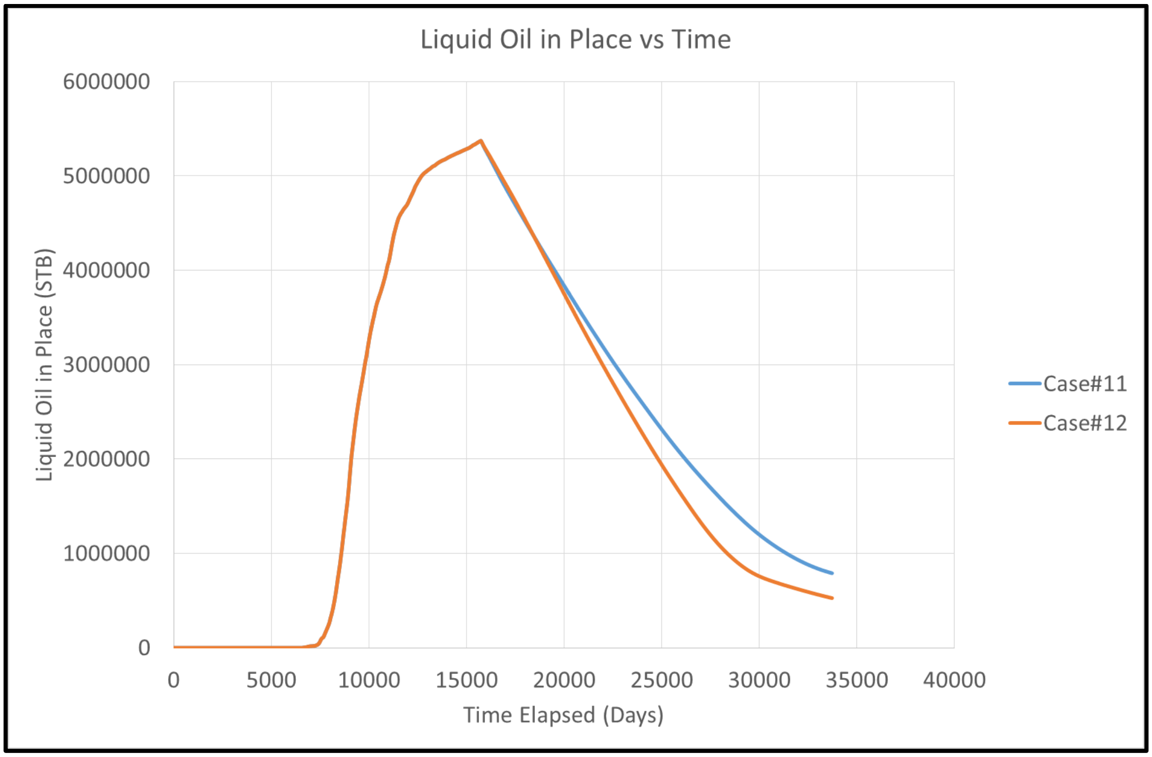

Figure 51. Liquid Oil in Place vs Time graph for Combination Injection Cases

The Figures 49 – 51 could be interpreted as Case#12 is better than Case#11. One will be immediately mistaken because the fact that Pressure drop and the Liquid oil content in the reservoir is better than Case#11 it is only caused by the dropping in production rates. Figure 52 shows the cumulative oil production of the reservoir.

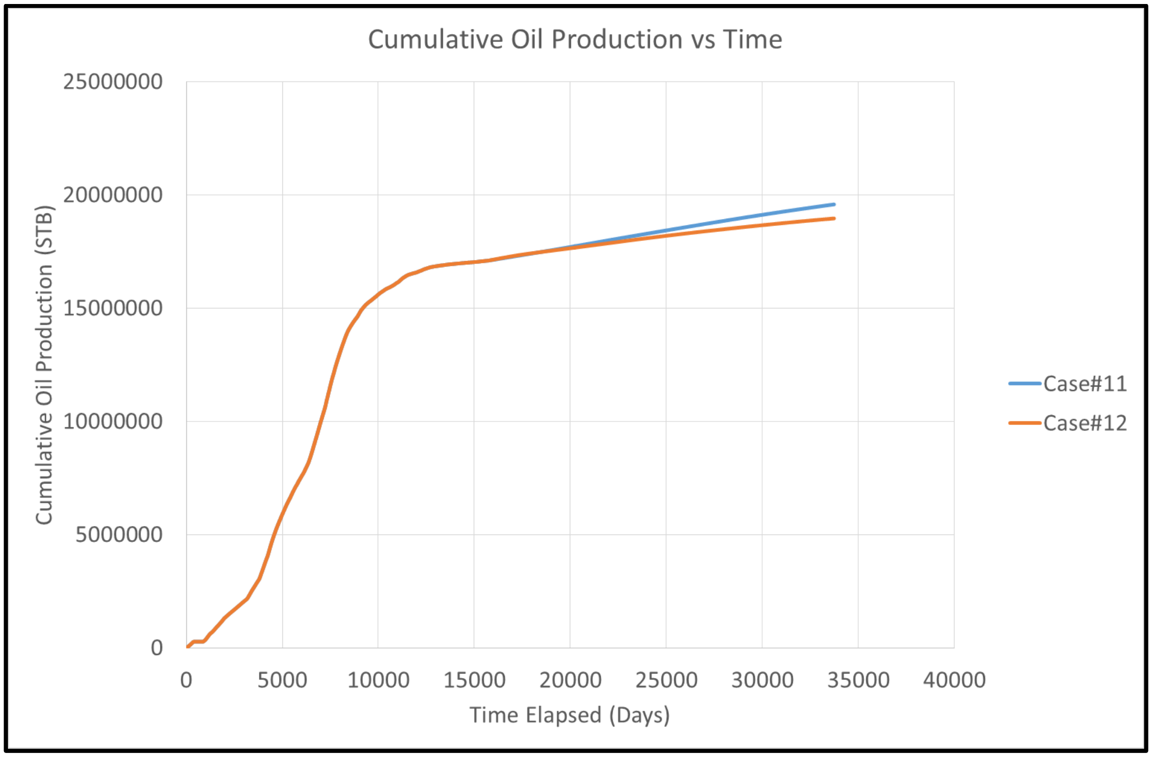

Figure 52. Cumulative oil Production for Combination Injection Cases

Although the results of the combination injection is very good it does not to be the only solution for gas condensate drop-out/blockage occur. Many other techniques such as chemical treatment, drilling horizontal wells should also investigated in terms of availability and economic aspects. In addition to these cases the suggested production strategy is further investigated in economic manner.

CHAPTER 8

CONCLUSION

There are several outcomes for this thesis work. Other than simulation processes the main focus of this thesis was to produce valuable gas condensate by keeping reservoir pressure higher than dew point pressure.

Outcomes of this thesis listed are below:

- The pressure decrease in the reservoir due to the production will leads to the condensate drop-out which forms a gas condensate blockage, to a certain saturation, thus the gas and condensate production will decrease.
- In order to achieve a sustainable production high rate, short timed production strategies should be avoided.
- The optimal way to produce from a gas condensate reservoir, without any injection, is to maximize the production but keeping the reservoir pressure higher than the dew point pressure and try to let condensate evolve at surface facilities rather than reservoir or in well bore.
- Due to incompressibility of water, water injection is a good way to keep the pressure high in the reservoir, however the injection can also cause water breakthrough problem at the production wells closer to the injection wells.
- In long term, gas injection could prove useful since the condensate production will increase but in short term, the amount of gas injected is coming from the produced gas therefore an economic analysis must have conducted.

- Combination injection is chosen to be the most appropriate injection strategy for this thesis work since the gas production rate could be increased and also condensate can form in the surface facilities due to increase in reservoir pressure.

REFERENCES

Ahmed, T. (1989). *Hydrocarbon Phase Behavior*. Houston, Texas: Gulf Publishing Company.

Ahmed, T. (2010). *Reservoir Engineering Handbook.* Amsterdam: Gulf Professional Pub.

Ali, F. (2014, June). Importance of water Influx and water flooding in Gas condesate reservoir. Trondheim, Norway: Norwegian University of Science and Technology.

Asgari, A, et al. (2013). Methanol treatment in gas condensate reservoirs: A modelling and experimental study. *Chemical Engineering Research and Desing*.

Buryakovsky, L., Chilingar, G., & Aminzadeh, F. (2001). *Petroleum Geology of the South Caspian Basin.* Boston: Gulf Professional Pub.

Djevanshir, R., & Mansoori, A. (2000). Introduction to South Caspian Basin Special Issue. *Journal of Petroleum Science and Engineering*, 153-155.

El-Banbi, A. H., & Aly, A. M. (2000). Investigation of Waterflooding and Gas Cycling for Developing a Gas-Condensate Reservoir. *SPE/CERI Gas Technology Symposium.* Calgary, Alberta, Canada: Society of Petroleum Engineers.

Ertekin, T., Abou-Kassem, J. H., & King, G. R. (2001). *Basic Applied Reservoir Simulation.* Richardson, Texas: Society of Petroleum Engineers.

Fevang, Ø., Singh, K., & Whitson, C. H. (2000). Guidelines for Choosing Compositional and Black-Oil Models for Volatile Oil and Gas-Condensate Reservoir. *SPE Annual Technical Conference and Exhibition.* Dallas, Texas: Society of Petroleum Engineers.

Niri, M. E. (2015). Seismic data integration and multi-objective optimization for 3D reservoir characterization and model building. Australia: University of Western Australia.

Riazi, M., & Daubert, T. (1980). Simplify Property Predictions. *Hydrocarbon Processing*, 115-116.

Sheydaeemehr, M., Sedaeesola, B., & Vatani, A. (2014). Gas-condensate production improvement using wettability alteration: A giant gas condensate field case study. *Journal of Natural Gas Science and Engineering*, 201-208.

Soave, G. (1972). Equilibirum constants from a modified Redlich-Kwong equation of state. *Chemical Engineering Science*, 1197-1203.

Spivak, A., & Dixon, T. (1973). Simulation of Gas Condensate Reservoir. *SPE Symposium on Numerical Simulation of Reservoir Performance* (pp. 11-12). Houston: Society of Petroleum Engineers.

Thornton, O. (1946). Gas-Condensate Reservoirs-A Review. *API Drilling and Production Practice* (pp. 150-159). New York: American Petroleum Institute.

Whitson, C. H., & Brulé, M. R. (2000). *Phase Behavior.* Richardson, Texas: Society of Petroleum Engineering.

Zakrevsky, K. (2011). *Geological 3D Modelling.* EAGE Publications.