YAMEN KHALILI

WELLBORE BUOYANCY VARIATIONS
DURING THE LIFE OF A RESERVOIR

MASTER THESIS

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NEAR EAST UNIVERSITY

INSTITUTE OF GRADUATE STUDIES

DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

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September, 2022

Approval

We certify that we have read the thesis submitted by Yamen KHALILI titled **"Wellbore Buoyancy Variations During the Life of a Reservoir"** and that in our combined opinion it is fully adequate, in scope and in quality, as a thesis for the degree of Master of Applied Sciences.

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Declaration

I hereby declare that all information, documents, analysis and results in this thesis have been collected and presented according to the academic rules and ethical guidelines of the Institute of Graduate Studies, Near East University. I also declare that as required by these rules and conduct, I have fully cited and referenced information and data that are not original to this study.

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Abstract

Wellbore Buoyancy Variations During the Life of the Reservoir

KHALILI, Yamen

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This research investigates the buoyancy variance regarding the change of some parameters at two different conditions: Regarding depth, temperature, and pressure then regarding time, gas-oil ratio, and pressure

The study is mainly focused on buoyancy changing in the well due to temperature (with depth) and gas-oil ratio (with time). Applications and studies are done on Trinidad and Tobago reservoir. Trinidad and Tobago, is a country island located in the Caribbean. Excel spreadsheet has been used to do the whole work where a lot of equations were used to be able to calculate buoyancy at each different level in the two different conditions of depth and time.

The study showed that the effect of the ratio of gas to oil on buoyancy is higher than that of temperature on it. It showed that buoyancy in Trinidad and Tobago reservoir can be changed more with gas lift than thermal injection where it is more affected by gas-oil ratio than temperature.

Keywords: Well-buoyancy pressure, gas lift, buoyancy versus temperature, buoyancy versus gas-oil ratio.

Özet

Rezervuarın Ömrü Boyunca Kuyu Deliği Kaldırma Kuvveti Değişimleri

KHALILI, Yamen
MSc., Petrol ve Doğal Gaz Mühendisliği Bölümü
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Bu araştırma, iki farklı koşulda bazı parametrelerin değişimine ilişkin kaldırma kuvveti varyansını incelemektedir: Derinlik, sıcaklık ve basınçla ilgili, ve Zaman, gaz-petrol oranı ve basınç ile ilgili
Çalışma esas olarak sıcaklık (derinlikle) ve gaz-petrol oranı (zamanla) nedeniyle kuyuda değişen kaldırma kuvvetine odaklanmıştır.

Trinidad rezervuarı üzerinde uygulama ve çalışmalar yapılmaktadır. Resmi olarak Trinidad Cumhuriyeti, Karayipler'in en güneydeki ada ülkesidir. İki farklı derinlik ve zaman koşulunda, her farklı seviyede kaldırma kuvveti hesaplayabilmek için birçok denklemin kullanıldığı tüm işi yapmak için Excel programı kullanılmıştır.

Çalışma, gaz-petrol oranının kaldırma kuvveti üzerindeki etkisinin, sıcaklığın üzerindeki etkisinden daha yüksek olduğunu göstermiştir. Trinidad rezervuarındaki kaldırma kuvvetinin, sıcaklıktan çok gaz-petrol oranından etkilendiği termal enjeksiyondan daha fazla gaz kaldırma ile değiştirilebileceğini göstermiştir.

Anahtar kelimeler: Kuyu kaldırma basıncı, gaz kaldırma, kaldırma kuvveti sıcaklığa karşı, kaldırma kuvvetine karşı gaz-petrol oranı.

Table of Contents

List of Tables

List of Figures

List of Abbreviations

GOR:	Gas-oil ratio
FVF:	Formation volume factor
Bo:	Oil formation volume factor
OC:	Oil column
GRV:	Gross rock volume
NG:	Net to gross ratio
Por:	Porosity
Sw:	Water saturation
Pb :	Bubble point pressure

CHAPTER I
Introduction

A body immersed in a fluid is subjected to an upwards force equal to the weight of the displaced fluid, according to Archimedes' principle. This is the initial equilibrium condition. The above force, which we call the force of buoyancy, is thought to be located in the center of the submerged hull, which we call the center of buoyancy. The floating body's center of gravity and its center of buoyancy must be on the same vertical, according to a second criterion known as Stevin's law. The initial and inclined waterplanes connect along a line going through the waterplane's centroid for a minor angle of inclination. The center of buoyancy moves along a curve whose center of curvature is called a metacenter for varying inclinations (Biran & Pulid, 2014).

Thesis Problem Statement

Buoyancy pressure in the well has a lot of question marks in front of it. It represents the well-head pressure that controls the produced oil level. The decline in crude oil level in the well had a lot of question. This research aims to study the effect of temperature and gas-oil ratio on buoyancy and well-head pressure and therefore to be able to know what a better artificial method is to use to enhance buoyancy: gas lift or thermal injection to the well.

Scope of Work

This research aims to study the effect of temperature and gas-oil ratio on buoyancy and well-head pressure and therefore to be able to know what a better artificial method is to use to enhance buoyancy: gas lift or thermal injection to the well.

Hypothesis

If buoyancy is studied level by level in the well during production vs two conditions: depth and time, there will be a one main factor affecting buoyancy and well-head pressure which should be scoped and studied well to have the better artificial lift method to apply to the well in order to have a better crude oil recovery with the lowest costs.

Key Objectives

The key objective of the study is to improve and produce as much oil as possible from the field before reservoir pressure is fully depleted thereby maximizing the profits from this Trinidad reservoir. To achieve this there is a need to:

- Assess different ways to increase the depth level of the remaining oil in the well instead of using a pump.
- Evaluate how to optimize secondary recovery methods mainly gas-lift which has been used in the early stages of production.

Structure of Thesis

The first chapter introduces the research and the motive behind it. It specifies the issues that are currently being faced within the oil industry and illustrates the aim and objectives of this thesis. The second chapter presents literature review on gas-oil ratio, buoyancy, crude oil density and its importance. The third chapter presents the methodology in detail while Chapter 4 gives valuable data from the results obtained from the methodology of this thesis. Chapter 5 contains conclusions and recommendations of this research.

Methodology

Microsoft-Excel is used throughout the research of this thesis to design a Calculation design for buoyancy through Trinidad reservoir. The existing data from the field was computed into the excel where several tests were carried out to be able to calculate buoyancy pressure. The tests are targeting two experiments

1- Buoyancy due to temperature change.
2- Buoyancy due to gas-oil ratio change

Limitation of the Study

The study is only limited to extensive literature research. This means that some variables which have not been published to the public will only have to be estimated realistically to obtain the desired results.

CHAPTER II
Literature Review

Buoyancy During Oil Migration

As the hydrocarbons move into the trap, the buoyancy of the light oil (or gas) forces the water in the pores laterally down. However, not all water moves. Some of it is kept in the pores by capillary forces. The narrower the capillary pores and the smaller the pore neck, the stronger the retention of water. The two forces acting on the liquid within the pore space are governed by physical laws.

The remaining volume of water at a particular depth in a reservoir is determined by the capillary forces taking water up from the hydrocarbon and water interface and gravity acting in concert with the difference in density between reservoir fluids to push the water down. As a result, within the hydrocarbon leg, a portion of the pore space can contain both hydrocarbons and water. Water saturation is defined as the proportion of water in total fluid volume (%) (Vavra et al., 1992).

The capillary-bound water in an oil field is a height of water within the oil column with a pressure gradient regulated by the water density. The oil will be a continuous phase in the remaining pore space, with a pressure gradient regulated by the oil density. Although oil and water can cohabit in a small area of rock, the pressures applied on each of the two fluids are not the same. With a height more than the free-water level, the pressure differential between the oil and water phases grows. In a huge open hole dug in the column of oil, the water-hydrocarbon contact would theoretically stand at the free-water level. Only gravity and buoyant forces are in control in this situation of the distribution of fluid in the borehole (Vavra et al., 1992).

The oil column will displace more water in an increasing order of the pore volume as the buoyancy force increases with height more than the level of free water. Hydrocarbon saturation rise with height above the hydrocarbon-water interface as a result of this. Thus, the distribution of fluids in oil and gas fields is governed by the relationship of buoyancy and capillary pressures. The precise estimate of hydrocarbon quantities within a reservoir requires a thorough understanding of these interactions. (Sneider,1992).

The quantities and beginning formation of petroleum for the secondary migration, the pattern of migration, the flux of hydrocarbons migration, and losses during migration define a secondary hydrocarbon migration system. The dominating force or combination of factors that affect migration is used to classify secondary hydrocarbon migration systems. Separate phase hydrocarbons are pushed by buoyancy forces in hydrostatic secondary hydrocarbon migration systems, which are directed vertically upwards with a magnitude highly dependent on hydrocarbon-water density differential and capillary forces. The tectonically produced lateral driving force for groundwater flow in basins near zones of plate convergence and continental collision may promote hydrocarbon lateral migration through accessible carrier rocks in basins away from the active zones. The hydrocarbon migration depends on two phases: Drainage and Imbibition. (Dong, 2021).

"Imbibition" refers to the increasing the saturation wetting-phase.

"Drainage" the process where saturation of a wetting phase decreases.

Gas Oil Ratio

It is typical for some natural gas to come out of solution while it is on the way to surface in well. The volume of gas ("SCF") that emerges from the solution to the volume of oil (bbl) under typical conditions is called as the gas/oil ratio (GOR).

Gas starts to go out of solution at bubble point pressure. The pressure where the first gas bubble occurs at a particular temperature is known as the "bubble-point pressure."

Gas begins to develop in the reservoir when it is exhausted, and its pressure goes under the bubble-point pressure. Since gas is more mobile than oil, it is anticipated that the producing GOR would rise when the pressure of the reservoir falls under the bubble point pressure.

There are three cases for calculating GOR (Ahmed & Meehan, 2012):

Case 1: Where there is no gas in the reservoir out of the oil when the reservoir pressure p is higher than the bubble point pressure pb:

GOR= R_{si} , where R_{si} is the solution gas ratio to oil.

Case 2: The gas starts to emerge from solution when the reservoir pressure falls below pb, and its saturation rises. However, before the saturation of gas reaches the critical gas saturation, the free gas went out of solution will not be able to flow:

GOR= R_{si}

Case 3: At this stage, the free gas starts to flow with the oil, and the GOR values rise significantly as the reservoir pressure drops which is shown in Equation 2.1:

$$GOR = Rs + (\frac{Krg}{Kro})(\frac{\mu o \beta o}{\mu g Bg}) \tag{2.1}$$

GOR= Gas–oil ratio at a certain time, scf/STB

R_s= Solubility of gas, scf/STB

k_{rg}=relative permeability of gas

k_{ro}=relative permeability of oil

B_o=oil formation volume factor, bbl/STB

B_g=gas formation volume factor, bbl/scf

μ_o= Viscosity of oil, cp

μ_g= Viscosity of gas, cp

GOR With Different Drives

Most important drives affecting GOR in the reservoir are:

1. Solution gas drive
2. Gas cap drive
3. Water drive
4. Gravity drainage

Solution gas drive**:** The process by which dissolved gas in a reservoir will expand and act as an energy source to create reservoir fluid is known as a solution gas drive. Other names for the solution gas drive are dissolved gas drive and depletion drive.

A reservoir is said to be "under saturated" when the pressure inside it exceeds the bubble point and there is no gas which is free in the reservoir present. At this point, the explosion of oil and connate water as well as the compacting of reservoir pore space provide the driving force. Only a limited quantity of fluid may be created since oil and rock have extremely low compressibilities.

Oil gets saturated and free gas is present in a reservoir when the pressure exceeds a bubble point. The major energy source used to create reservoir fluid for the solution gas drive is the expansion of gas. As free gas in a reservoir cannot move until it be more than the the critical gas saturation, the generated gas oil ratio will initially slightly fall. After then, gas will start to enter a well. Where vertical permeability is great, gas may occasionally migrate up and produce a secondary gas cap, aiding in the production of oil.

More gas will be generated when pressure drops, but less oil will be produced. This will result in a high gas to oil production ratio. Solution gas drive diagram is shown in Figure 2.1.

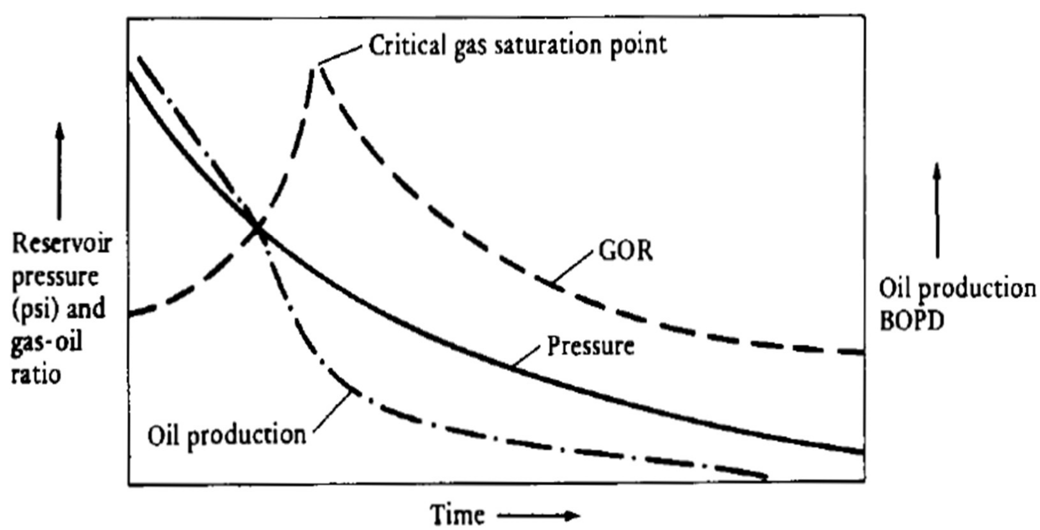

Figure 2.1. *Solution gas drive (Selly, 1998).*

Gas cap drive**:** Where the field has both oil and gas, is a second producing mechanism. Gas that has been dissolved in oil starts to emerge from the solution when production gets underway due to the pressure reduction. This fresh gas ascends to the gas cap and explodes as a result to fill the pores left empty by the oil. Gas cap drive diagram is shown in Figure 2.2.

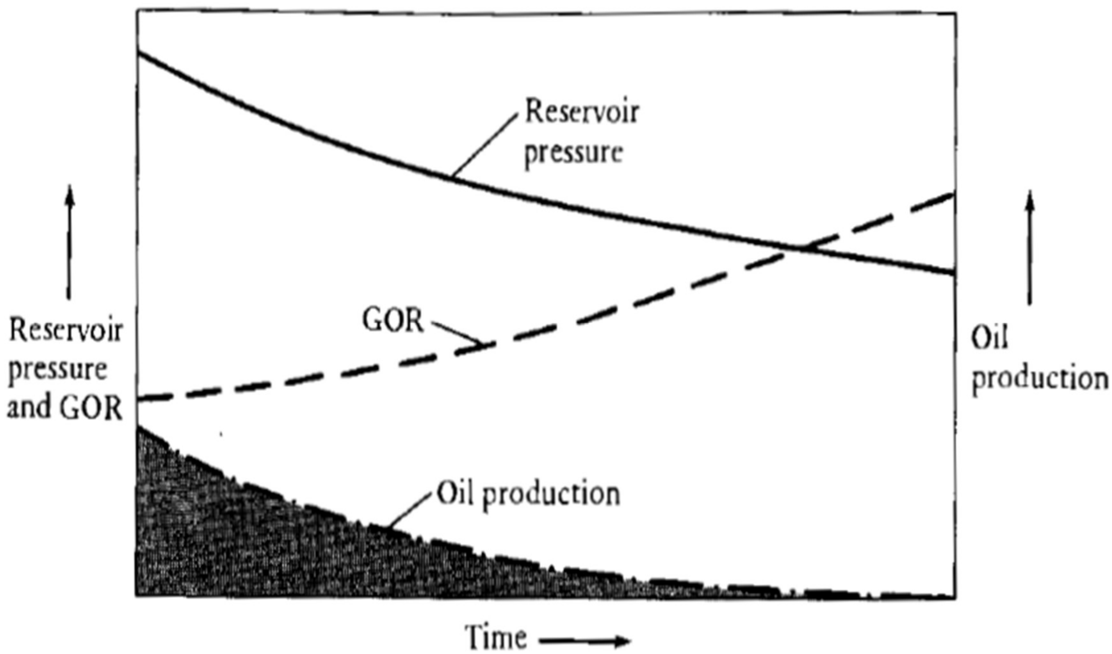

Figure 2.1. *Gas Cap Drive (Selly, 1998).*

Water drive: It is the case where the oil reservoir is surrounded by a huge aquifer of water that maintains reservoir pressure and keeps it constant. This is mainly because water fills the pores left by the produced oil through the producing well leading to a preserve of reservoir pressure. This drive has no effect on GOR. Figure 2.3 shows water drive diagram.

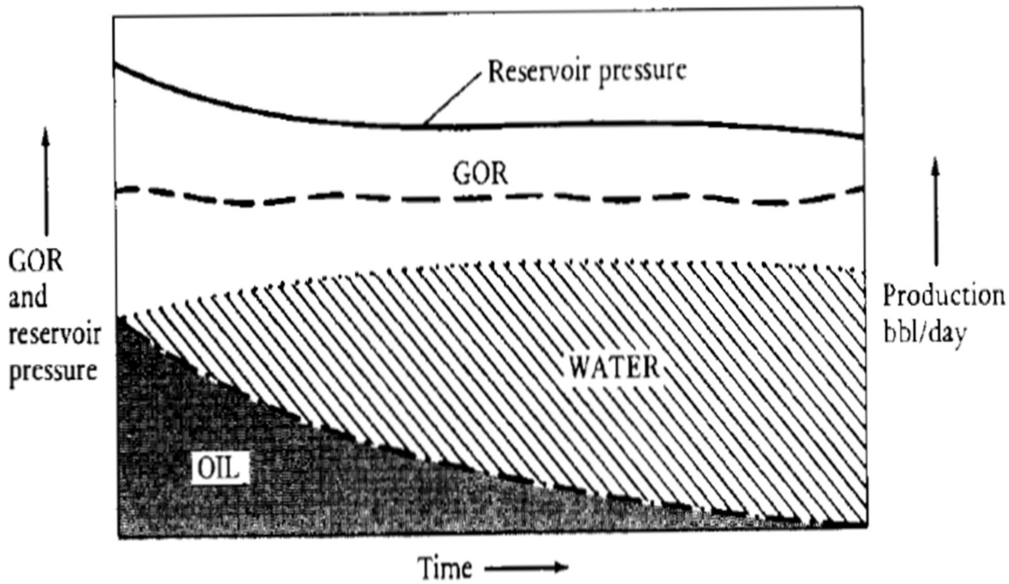

Figure 2.2. *Water drive diagram (Selly, 1998).*

Oil Formation Volume Factor

Oil formation volume factor, Bo, is the volume of oil and the gas dissolved in it at the reservoir temperature and pressure divided by volume of crude oil at surface standards. Bo should be more than or equal to one. The oil formation volume factor (Ahmed,2010) can be expressed mathematically as shown in Equation 2.2:

$$Bo = (Vo)p,t/(Vo)sc \qquad (2.2)$$

Where:

B_o = Formation volume factor of Oil, bbl/STB

$(V_o)p,T$ = Volume of oil at standard conditions, bbl.

$(V_o)_{sc}$ = Volume of oil is at surface standards, STB

A new correlation has been estimated in 2011 (Hassn & Sadiq, 2009) for the calculation of oil formation volume factor where:

$$B_o = a_1\, P^{a2}\, T^{a2}\, API^{a4}\, y_g^{a5} + a_6 \qquad (2.3)$$

Where:

Bo= Formation volume factor of oil (fraction).

P= Pressure (psi).

T= Temperature (F).

Yg= Specific gravity of gas (g/cc).

List of values of coefficients of Equation 2.3 is shown in Table 2.1:

Table 2.1

List of values of coefficients of the Equation 2.3 **(***Sadiq, D. 2009).*

Coefficient	The Value
a_1	0.000005
a_2	0.639887
a_3	0.604183
a_4	0.961566
a_5	1.041364
a_6	1.079483

FVF Relation with Reservoir Pressure

Oil formation volume factor versus pressure is shown in Figure 2.4:

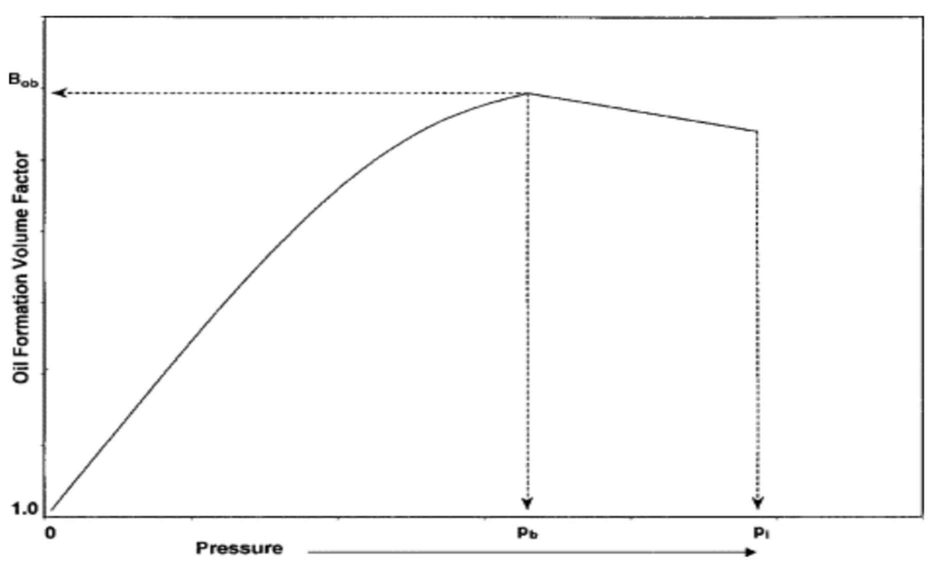

Figure 2.3. *Bo vs pressure (Ahmed, 2006).*

As it is shown in the Figure 2.4, oil formation volume factor increases slightly after production started and reservoir pressure starts to decrease reaching pressure at the bubble point, but after bubble point pressure is reached, a significant decrease of formation volume factor of oil with the pressure of the reservoir decrease is observed to reach its minimum which is equal to 1. This is mainly because the formation volume factor of oil is dependent on the main reservoir properties that changes with pressure change such as GOR.

GOR and FVF Relationship

$$GOR = Rs + \left(\frac{Krg}{Kro}\right)\left(\frac{\mu o\beta o}{\mu gBg}\right) \tag{2.4}$$

Where:

GOR = Gas-oil ratio at a certain time, scf/STB

R_s = Solubility of gas, scf/STB

k_{rg} = relative permeability of gas

k_{ro} = relative permeability of oil

B_o = Formation volume factor of oil, bbl/STB

B_g = Formation volume factor of gas, bbl/scf

μ_o = Viscosity of oil, cp

μ_g = Viscosity of gas, cp

The Equation 2.4 reveals that formation volume factor of oil is directly proportional to ratio of gas to oil whereas this ratio increases formation volume factor of oil increases and as gas to oil ratio decreases, formation volume factor of oil decreases.

Oil Density Change with Pressure

The density of oil is represented as the mass per volume. In the units of oil industry, density is represented in the unit of lb/ft^3. Oil density is often calculated at the reservoir conditions.

The oil density in most oil reservoirs falls when pressure is lost until it is more than the bubble point. The more oil molecules that are packed into the same unit volume results in a greater oil density at higher pressures. Gas escapes from solution and creates free gas when pressure goes less than the bubble-point pressure. Some of the oil's intermediate constituents will be contained in the expelled gas, leaving the constituents with more weight in the oil from the reservoir. The density versus pressure trend below the bubble-point pressure can be attributed to this release of intermediate components. Crude oil density vs pressure is shown in Figure 2.5.

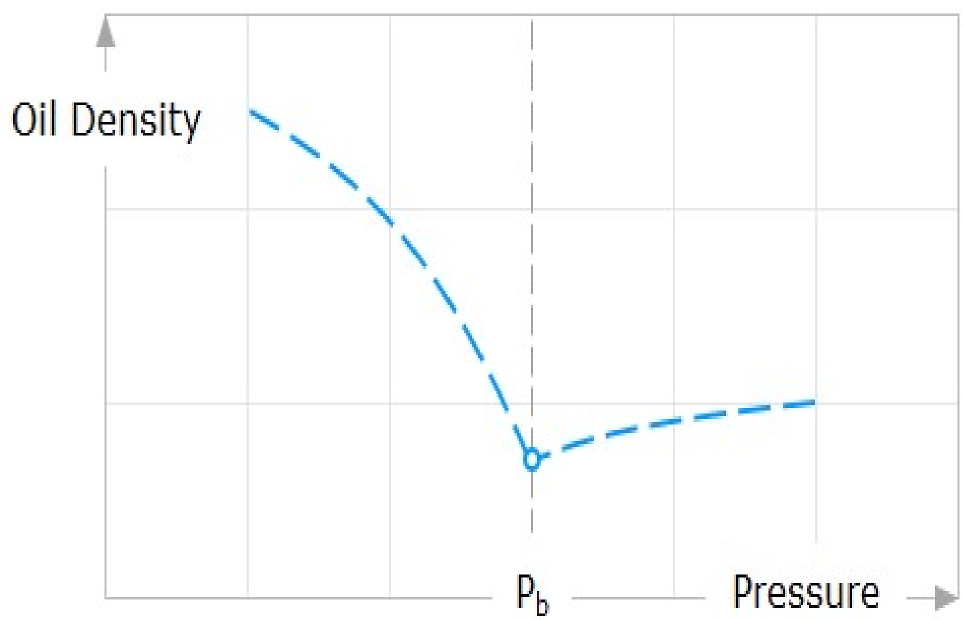

Figure 2.4. *Oil density vs pressure (El-Banbi, 2018).*

As it is shown in Figure 2.5, Oil density decreases slightly before bubble point pressure is reached due to no solution gas is liberated, but after bubble point is reached oil density start to increase significantly whereas pressure decreases oil density increases due to gas-oil ratio decrease where solution gas starts to go out of oil.

Oil Density Change with Gas Oil Ratio

Crude oil density changes in the reservoir and the well are mainly based on gas-oil ratio change (increase and decrease).

As shown in the chapters mentioned before, it is shown that as reservoir pressure decreases, gas oil ratio decreases.

Also it is shown that, (in crude-oil density vs pressure chapter), as reservoir pressure decreases, crude oil density increases.

This is due to the process by which dissolved gas in a reservoir will expand and act as an energy source to create reservoir fluid is known as a solution gas drive. Other names for the solution gas drive are dissolved gas drive and depletion drive.

A reservoir is called "under saturated" when the pressure inside it exceeds the bubble point and there is no gas free in the reservoir present. At this point, the explosion of oil and connate water as well as the compacting of reservoir pore space provide the driving force. Only a limited quantity of fluid may be created since oil and rock have extremely low compressibilities.

Oil gets saturated and free gas is present in a reservoir when the pressure is more than the bubble point. The major energy source used to create reservoir fluid for the solution gas drive is the expansion of gas. As free gas in a reservoir cannot move until it goes higher than the critical gas saturation, the generated gas oil ratio will initially slightly fall. After then, gas will start to enter a well. Where vertical permeability is great, gas may occasionally migrate up and produce a secondary gas cap, aiding in the production of oil. More gas will be generated when pressure drops, but less oil will be produced. This will result in a high gas to oil production ratio.

As depth is decreased, pressure is decreased which leads to solution gas going out of the crude oil leading to a higher density.

Therefore, as gas-oil ratio decreases, crude oil density increases.

Buoyancy Changes with Density

Crude-oil Density increases after bubble point with GOR decrease. In physics:

$$\text{Buoyancy Force= weight of oil=} \quad \rho_{(water)} * V_{(displacing\ object\ or\ fluid)} * g \qquad (2.5)$$

Where:

- p(water)= Water density (g/cc)
- V= Volume of displacing object (cm^3)
- g= gravitational force constant (cm/sec^2).

In petroleum engineering: Buoyancy Pressure= $(\rho_{(water)} - \rho_{(oil)})*g * h$ (2.6)

Where:

- Pb= Buoyancy pressure (g/cm^2).
- Pw= water saturation (g/cc).
- Po= Crude oil density (g/cc).
- ho= Oil column (cm).
- g= gravitational force constant (cm/sec^2).

Depending on the two equations, as oil density increases buoyancy decreases. Therefore, Buoyancy is directly proportional to gas-oil ratio and inversely proportional to crude oil density.

Well-Head Pressure

Well-head pressure is the pressure at the top of the well, i.e., at its wellhead. It is calculated by pressure gauges of the wellhead specific measurers. There are two kinds of well-head pressure: static and dynamic wellhead pressures.

The reservoir pressure, well depth, and filling medium density all affect the wellhead pressure (static), which is measured in the well which has been abandoned. It is equivalent in numbers to the subtraction between of reservoir pressure and the hydrostatic pressure of the liquid thickness extending from the wellhead to the reservoir.

Operating well is used to measure dynamic wellhead pressure, which is dependent on the same factors as static wellhead pressure plus the rate of the well, the flow rate of the injection agent, the pressure in the pipeline nearby, and the difference in pressure in the shut-off components of the wellhead fittings.

The part that forms the structural and pressure-containment interface for the drilling and production machinery is known as a wellhead, and it is located at the top of an oil or gas well. A wellhead's main function is to act as a suspension point and pressure seal for the casing strings that connect the bottom of the hole sections to the surface pressure control apparatus.

A blowout preventer controls surface pressure when digging the oil well (BOP). A well blowout might happen if the drilling fluid column, casings, wellhead, and BOP are not able to keep the pressure under control.

$$\text{Well-head pressure} = \text{Reservoir pressure} - \text{Hydrostatic pressure.} \tag{2.7}$$

CHAPTER III
Methodology

Trinidad Reservoir Properties

Applications and studies are done on Trinidad reservoir. Officially the Republic of Trinidad, is the southernmost island country in the Caribbean. It is considered as a hot country with a surface temperature of 80°F. The reservoir properties are shown in Table 3.1:

Table 3.1

Trinidad reservoir properties(Iyare, 2012).

Parameters	**Values**
Field size	69 Acres
Average column thickness	Gas- 166 ft
	Oil – 63 ft
	Aquifer – 215 ft
Net to gross sand ratio	0.95
Average porosity	30%
Average permeability	1000 mD
Rock compressibility	5.7* 10^-6 psi^{-1}
Reservoir pressure	4934 psi
Reservoir temperature	173°F
Oil API gravity	34.2
Average depth to GOC	10022 ft
Average depth to WOC	10085 ft
Initial datum pressure	4934 psi
Datum depth	10096 ft
Bubble point pressure @ GOC	4855 psi
Formation volume factor (Bo)	1.403 RB/STB
Average water saturation	0.13

Table 3.1 (Continued).

Water density	62.238 lb/ft^3
Fluid viscosity	0.614 cp
Water compressibility	3.0E-6 psi^{-1}
Pressure gradient	0.49 psi/ ft

Temperature Gradient Estimation for Trinidad Reservoir

There are two ways to calculate formation temperature with some givens which are:

1. Temperature gradient estimation using formation temperature estimation graph from well logging charts.
2. Temperature gradient calculation using formation temperature equation

Formation temperature vs depth is shown in Figure 3.1:

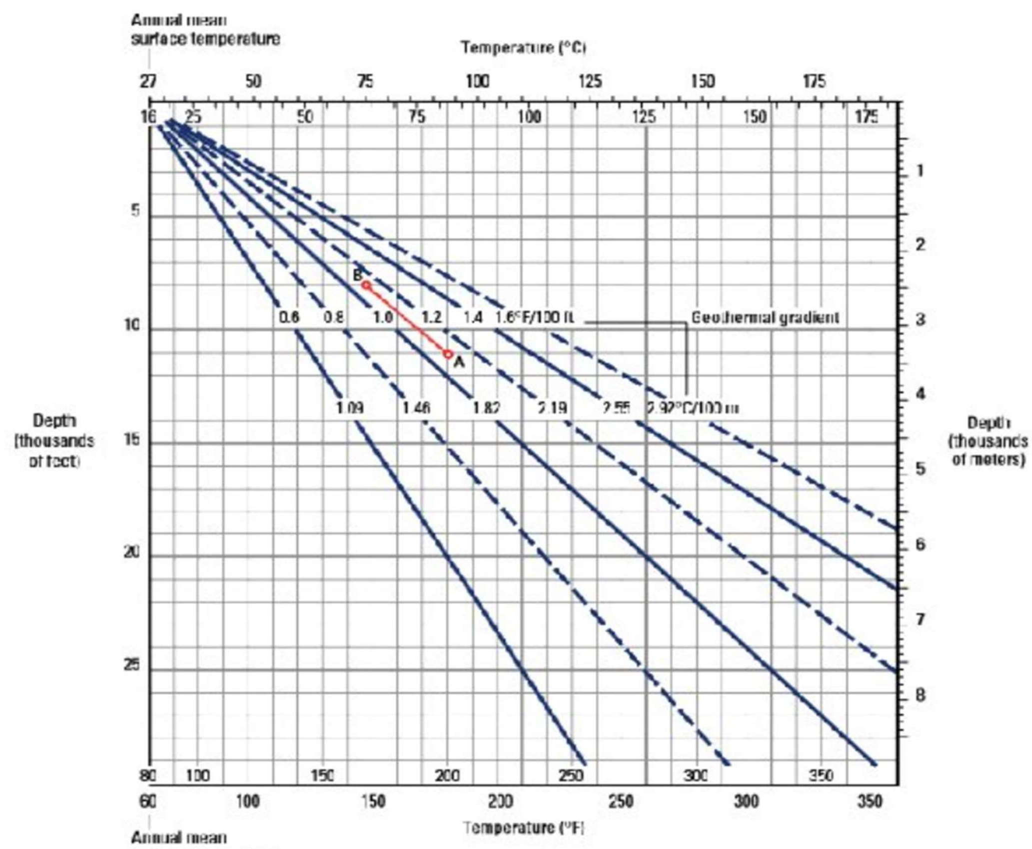

Figure 3.1. *Formation temperature vs depth (Schulumberger, 2000).*

1. Temperature Gradiant Estimation Using Formation Temperature Estimation Graph from Well Logging Charts:

   Using the formation temperature estimation present in the graph in Figure 3.1. above, and using Trinidad reservoir properties in Table 3.1 , temperature gradient can be estimated.

   The initial reservoir depth is about 10085 ft.

   The initial reservoir temperature is 173°F.

   The intersection point between the two lines elongated vertically and horizontally respectively from 173°F and 10085 ft is the temperature gradient which is estimated from the graph as 0.9°F/ 100ft.

   This value is multiplied by 10^{-2} to be per every single foot which is equal to 0.009°F/ ft. Therefore, temperature gradient is equal to 0.009°F/ ft.

2. Temperature Gradient Calculation Using Formation Temperature Equation:

Temperature gradient can be also calculated by using formation temperature equation which is as follows:

Formation temperature (°F) = ambient surface temperature (°F) + (temperature gradient (°F/ft) x Well true vertical depth (ft))

Therefore, Temperature gradient= (formation temperature- ambient surface temperature) / well true vertical depth.

$$T_g = (T_f - T_s) / TVD \tag{3.1}$$

Where:

Tg= Temperature gradient (°F/ft)

Tf= Formation temperature (°F)

Ts= Ambient surface temperature (°F)

TVD= True vertical depth (ft)

Parameters used in Trinidad reservoir:

- T_f= 173ºF
- T_s= 80ºF (Because Trinidad is considered as a hot country)
- TVD= 10085 ft

Therefore, Temperature gradient in Trinidad reservoir is equal to (173-80)/10085= 0.009ºF/ ft

Crude-Oil Density Calculation vs Depth, Temperature, and Pressure

The aim is to calculate oil density at different assumed depth from reservoir depth to surface in ft, also at different pressures and temperatures where pressure and temperature should be calculated at depth assumed.

In order to do that, a temperature, pressure vs oil density is found for another reservoir properties which is shown in Figure 3.2:

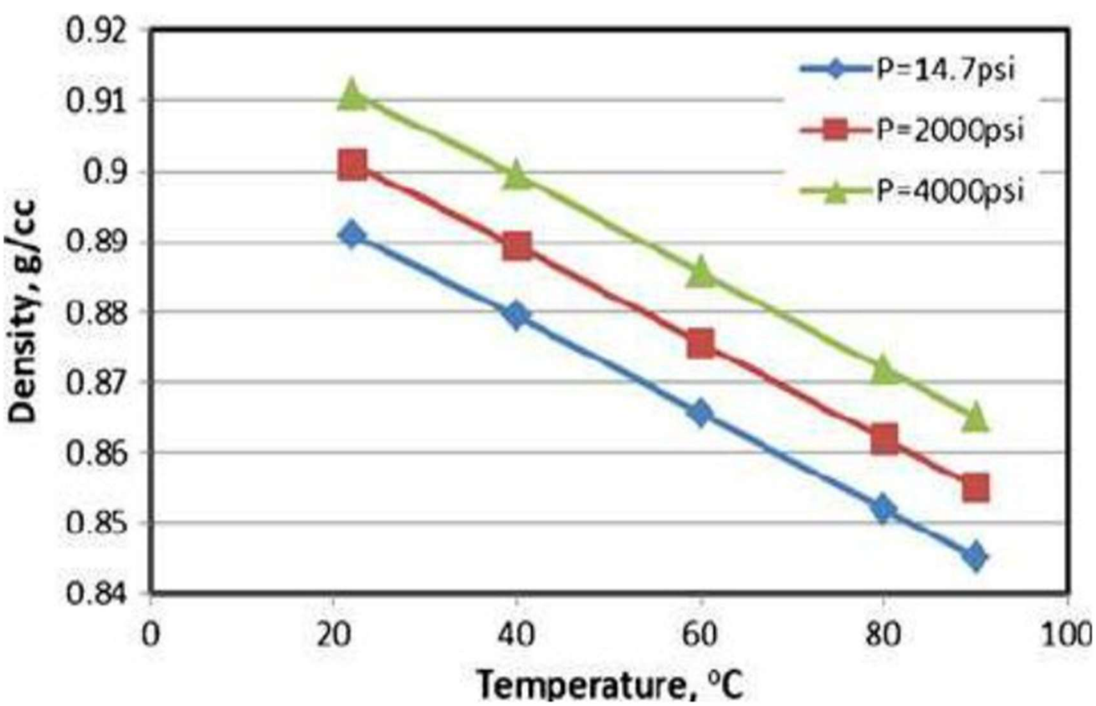

Figure 3.2. *Crude oil density vs temperature and pressure (Karnanda, 2010).*

Figure 3.2 shows crude oil Density change versus temperature at three different pressures: 4000 psi, 2000 psi and 14.7psi which the surface pressure.

Reservoir properties of Trinidad are applied to the graph in Figure 3.2 to have the same graph for our reservoir properties.

API= (141.5/Sg)-131.5), API= 34.2

Therefore, oil density at surface pressure equals to 0.853. According to that, the starting point on the new graph was oil density equals to 0.853 at 14.7 psi and 80ºF (27ºC). Parallel line is drawn from that point parallel to the line in the above picture from 20ºC to 90^{0}C at 14.7 psi.

Then, the same difference between the 2000 psi pressure line and 14.7 psi line is applied to the new reservoir properties between 20ºC to 90^{0}C.

Then, the same difference between the 4000-psi pressure line and 2000 psi line in the other reservoir graph is applied to the new reservoir properties graph between 20ºC to 90^{0}C.

All this work is done using excel program facility and the Trinidad reservoir pressure, temp and crude oil density graph is obtained and is showed Figure 3.3:

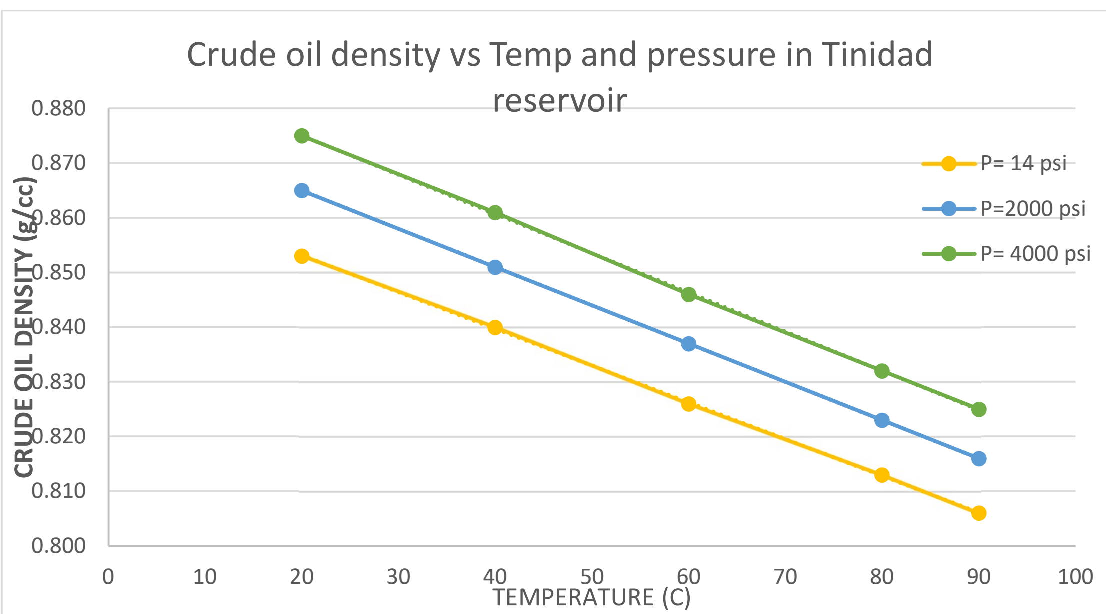

Figure 3.3. *Crude oil density vs temperature in Trinidad reservoir.*

The graph shows that as temperature decreases with depth at a constant pressure at each line, crude oil density increases.

The aim is to find density at each pressure and temperature level, but as it is shown, it is hard to get density at each different pressure level using the graph so a new correlation for crude oil density, pressure and temperature equation should be estimated to be used on Trinidad reservoir where crude oil density can be calculated at each different pressure and temperature level.

First, linear equations of each of the three pressure lines are estimated using excel trendlines which are as follows:

At 14.7 psi: Crude oil density = -0.0007(T) + 0.8666 (g/cc)

At 2000 psi: Crude oil density = -0.0007(T) + 0.879 (g/cc)

At 4000 psi: Crude oil density= -0.0007(T) + 0.8894 (g/cc)

The three equations are merged together to have a new correlation that can be applied at any temperature and pressure to calculate crude oil density. The new correlation is estimated which is as follows:

$$\rho o = -0.0007T + \{(52x10^{-3})P + 0.8686 \qquad (3.2)$$

Where:

$\mathcal{P}o$= Crude oil density (g/cc)

T= Temperature at a certain depth ©

P= Pressure at a certain depth (psi)

Equation-2.8 can be applied at any temperature and pressure for the aim of crude oil density calculation in Trinidad reservoir.

Now, crude oil density can be determined at each temperature and pressure level, but pressure and temperature should be first calculated at each level to be able then to estimate crude oil density at each level.

Twenty-five depth levels are assumed for Trinidad reservoir between reservoir depth (10085 ft) and close to surface depth (33 ft).

Pressure Calculation at Each Assumed Depth

Pressure is calculated at each different assumed depth using the given pressure gradient which is equal to 0.49 psi/ft.

The equation used for instant pressure calculation is shown in Equation 3.3:

$$Pi = (TVD\ x\ Pg) + Ps \tag{3.3}$$

Where:

Pi= Instant pressure at a certain depth (psi)

TVD= True vertical depth (ft)

Pg= Pressure gradient (psi/ft)

Ps= Surface pressure

Surface pressure is equal to 14.7 psi. Equation 3.3 is applied to each assumed depth in the depth Table which is showed in Table-3.2.

Temperature Calculation at Each Assumed Depth

Temperature is calculated at each different assumed depth using the given calculated temperature gradient which is equal to 0009ºF/ft.

The equation used for instant temperature calculation is shown in Equation 3.4:

$$Ti = (Tgx\ TVD) + \mathrm{Ts} \tag{3.4}$$

Where:

Ti= Instant temperature at a certain depth (F)

Tg= temperature gradient (ºF/ft)

TVD= True vertical depth (ft)

Ts= Surface temperature (F)

The surface temperature in Trinidad is 80ºF as it is discussed before. Table 3.2 shows temperature at each depth in ºC and ºF.

Crude Oil Density Calculation at Each Assumed Depth

Crude oil density is calculated at each different depth, temperature and pressure. The calculation was done using the following estimated equation before Equation 3.5:

$$\mathcal{P}o = -0.0007T + \{(52x10^{-3})P + 0.8686 \quad (3.5)$$

Where:

$\mathcal{P}o$= Crude oil density (g/ccc)

T= Temperature at a certain depth ©

P= Pressure at a certain depth (psi)

Equation 3.5 above can be applied at any temperature and pressure for the aim of crude oil density calculation in the Trinidad reservoir.

The calculated crude oil density vs depth is calculated and shown in the Table 3.2:

Table 3.2

Crude oil density at each level.

Depth(ft)	**Pressure (psi)**	**Temperature ©**	**Temperature (F)**	**Oil density by equation (g/cc)**
10085	4934	78	173	0.839
9666	4745	76	169	0.840
9247	4540	74	166	0.840
8828	4335	72	162	0.841
8410	4130	70	158	0.841
7991	3925	68	154	0.842
7572	3720	66	150	0.842
7153	3515	63	146	0.842
6734	3310	61	142	0.843
6315	3105	59	138	0.843
5897	2900	57	135	0.844
5478	2695	55	131	0.844

Table 3.2 (Continued).

5059	2490	53	127	0.845
4640	2285	51	123	0.845
4221	2080	48	119	0.846
3802	1875	46	115	0.846
3384	1670	44	111	0.846
2965	1465	42	107	0.847
2546	1260	40	104	0.847
2127	1055	38	100	0.848
1708	850	35	96	0.848
1289	645	33	92	0.849
870	440	31	88	0.849
452	235	29	84	0.851
33	14	27	80	0.853

As shown Table 3.2, it is shown that oil density increases with the decrease in depth, pressure, and temperature even with a constant Gas oil ratio.

Water density is given as 1 g/cc. In production engineering calculation, gas solubility change in formation water is usually neglected and water viscosity and density are assumed to be constant.

The gravitational force constant is given as 9.81 m/sec^2. But in the buoyancy equation, the gravitational force constant should be converted to cm/sec^2 which is equal to 981 cm/sec^2 and it is assumed constant with depth.

Depth values are converted from ft to cm, which is necessary for buoyancy calculation,

where 1 ft= 30.48 cm.

In this study, oil column is assumed to be constant because if gas-oil ratio is constant, oil column will not be changing which is equal to 63 ft= 1920 cm.

Buoyancy Calculation Due to Crude Oil Density, Temperature, Pressure, and Depth

Buoyancy has been calculated due to the four factors change mentioned above using the equation of buoyancy Equation 3.6 estimated before for Trinidad reservoir which is:

$$\mathcal{P}b = (pw - po) * ho * g \tag{3.6}$$

Where:

Pb= Buoyancy pressure (g/cm^2).

Pw= water saturation (g/cc).

Po= Crude oil density (g/cc).

ho= Oil column (cm).

g= gravitational force constant (cm/sec^2).

The buoyancy calculation at each depth, pressure, temperature and crude oil density are shown in Table 3.3. It is observed that buoyancy is decreasing due to depth decrease, temperature decrease, pressure decrease, and crude oil density increase.

Buoyancy is then converted from (g/cm^2) to (Pascal) where 1 g/cm^2 = 10^{-1} Pascals.

The converted buoyancy values are shown in Table 3.3. The buoyancy is converted from pascals to reservoir's SI unit which is psi where 1 Pa= 0.000145037738 psi.

Table 3.3

Calculated buoyant pressure in psi at each calculation level.

Depth(ft)	**Pressure (psi)**	**Temperature (F)**	**Buoyant pressure (g/cm^2)**	**Buoyancy (Pa)**	**Buoyancy (psi)**
10085	4934	173	302704	30270	439
9666	4745	169	301716	30171	438
9247	4540	166	300885	30088	436
8828	4335	162	300055	30005	435
8410	4130	158	299225	29922	434
7991	3925	154	298394	29839	433
7572	3720	150	297564	29756	432

Table 3.3 (Continued).

7153	3515	146	296734	29673	430
6734	3310	142	295903	29590	429
6315	3105	138	295073	29507	428
5897	2900	135	294242	29424	427
5478	2695	131	293412	29341	426
5059	2490	127	292582	29258	424
4640	2285	123	291751	29175	423
4221	2080	119	290921	29092	422
3802	1875	115	290090	29009	421
3384	1670	111	289260	28926	420
2965	1465	107	288430	28843	418
2546	1260	104	287599	28759	417
2127	1055	100	286769	28676	416
1708	850	96	285938	28593	415
1289	645	92	285108	28510	414
870	440	88	284278	28427	412
452	235	84	280680	28068	407
33	14	80	276912	27691	402

Buoyancy versus crude oil density graph is shown in Figure 3.4:

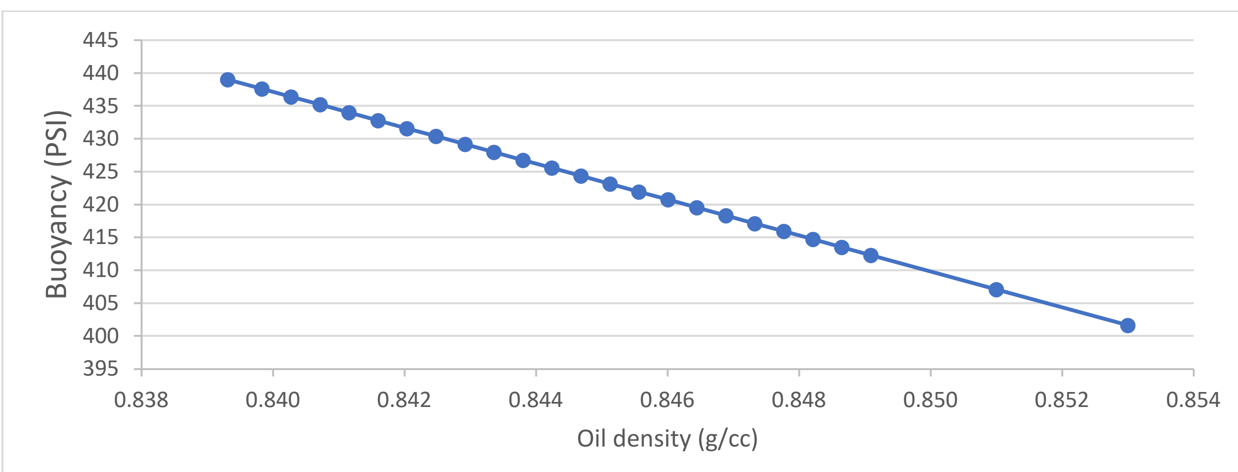

Figure 3.4. *Buoyancy vs crude oil density.*

Depending on the above study, it is observed that due to the four factors: crude oil density, temperature, pressure, and depth buoyancy has decreased from 439 psi to 402 psi.

Buoyancy Changes Due to Gas-Oil Ratio, and Pressure

This study aims to study the buoyancy changes due to time factor, where during time two main factors are changing which are: Gas-oil ratio and pressure. Temperature is considered constant due to time.

After a few years, reservoir pressure decreased from 4934 psi to 2000 psi. The study is based on the time period when pressure decreases from 4934 to 2000 psi. Pressure levels are assumed between a pressure of 4934 psi and 2000 psi. Table 3.4 showing pressure distribution with time, it is assumed that pressure decreases equally every 6 months:

Table 3.4

Pressure change with time.

Pressure (psi)	Time (years)
4934	0.5
4738	1
4543	1.5
4347	2
4152	2.5
3956	3
3760	3.5
3565	4
3369	4.5
3174	5
2978	5.5
2782	6
2587	6.5

Table 3.4 (Continued).

2391	7
2196	7.5
2000	8

Solution gas-oil ratio (Rs) is calculated at each different assumed pressure. The solution gas-oil ratio (Rs) calculation is done using Equation 3.7:

$$Rs = y_g(\frac{p}{18}\frac{10^{0.0125\,(API)}}{10^{0.0009}})^{1.2048} \quad (3.7)$$

Where:

Rs= Solution gas oil ratio (scf/STB).

P= Instantaneous pressure at a certain period (psi).

Yg= Gas specific gravity (g/cc).

t= Temperature (F)

The calculated solution gas-oil ratio values at each different assumed pressure level are shown in Table 3.5 as follows:

Table 3.5

Solution gas-oil ratio at each level.

Pressure (psi)	**GOR (scf/stb)**
4934	984
4738	937
4543	891
4347	845
4152	799
3956	754

Table 3.5 (Continued).

3760	709
3565	665
3369	621
3174	578
2978	536
2782	493
2587	452
2391	411
2196	371
2000	331

Table 3.5 shows that the solution gas-oil ratio decreased from 984 scf/stb to 331 scf/stb. Oil formation volume factor is calculated at each different assumed pressure using pressure, temperature and the calculated solution gas-oil ratio.

The equation used to calculate oil formation volume factor is Equation 2.3 mentioned in chapter 2 and it is as follows:

$$B_o = a_1 P^{a2} T^{a2} API^{a4} y_g^{a5} + a_6 \qquad (2.3)$$

Where:

Bo= Oil formation volume factor (fraction).

P= pressure (psi).

T= Temperature (F).

Yg= Gas specific gravity (g/cc).

The list of values of coefficients of Equation 2.3 is shown in Table 3.6:

Table 3.6

The list of values of coefficients of the equation.

Coefficient	The Value
a_1	0.000005
a_2	0.639887

Table 3.6 (Continued).

a_3	0.604183
a_4	0.961566
a_5	1.041364
a_6	1.079483

The calculated oil formation volume factor values at each assumed level are shown in Table 3.7:

Table 1.7

Calculated Bo at different levels.

Pressure (psi)	**Rs (scf/stb)**	**Bo**
4934	984	1.411
4738	937	1.403
4543	891	1.394
4347	845	1.385
4152	799	1.376
3956	754	1.367
3760	709	1.358
3565	665	1.349
3369	621	1.339
3174	578	1.329
2978	536	1.319
2782	493	1.309
2587	452	1.299
2391	411	1.288
2196	371	1.277
2000	331	1.266

It is observed that oil formation volume factor decreased from 1.411 to 1.266 due to pressure and gas-oil ratio decrease.

Oil Density Calculation to Gas-Oil Ratio Change

Oil density has been calculated at each different calculated gas oil ratio. The calculation was done depending Equation 3.8 Below:

$$po = (62.42796 * yo + 0.0136 * yg * Rs)/Bo \tag{3.8}$$

Where:

Po= Oil density (lb/ft^3)/

yo= Oil specific gravity (g/cc)

yg= Gas specific gravity (g/cc)

Bo= Oil formation volume factor (fraction).

The calculated values are in the unit of lb/ft^3 and are converted to g/cc, where 1 lb/ft^3= 0.02 g/cc.

The calculated oil density values in lb/ft^3 and the converted one's to g/cc are shown in the following table (Table 3.8):

Table 3.8

Calculated oil density at each level due to gas-oil ratio change.

Oil density due to GOR change (lb/ft3)	Oil density (g/cc)
52.809	0.8459
52.783	0.8465
52.763	0.8471
52.750	0.8477
52.744	0.8483
52.745	0.8489
52.755	0.8495

Table 3.8 (Continued).

52.773	0.8501
52.801	0.8507
52.840	0.8513
52.890	0.8519
52.952	0.8525
53.029	0.8531
53.121	0.8537
53.230	0.8543
53.358	0.8549

It is observed in Table 3.8 that oil density increased from 0.8459 g/cc to 0.8549 g/cc during that period.

Buoyancy Calculation Due to Gas-Oil Ratio, Pressure, and Time

Water density is given as 1 g/cc. In production engineering calculation, gas solubility change in formation water is usually neglected and water viscosity and density are assumed to be constant.

The gravitational force constant is given as 9.81 m/sec^2. But in the buoyancy equation, the gravitational force constant should be converted to cm/sec^2 which is equal to 981 cm/sec^2 and it is assumed constant with time.

Oil column is calculated at each different pressure, oil formation volume factor, and gas oil ratio.

The calculation was done based on Equation 3.9:

$$OC = \frac{GRV * NG * \emptyset * (1 - Sw)}{Bo} \quad (3.9)$$

Where:

OC= Oil column (cm).

GRV= Gross rock volume (cm^2).

NG= Net to gross ratio

Por= Porosity (fraction).

Sw= Water saturation.

Bo= Oil formation volume factor (fraction).

Givens:

GRV= 10900 cm^2

Porosity= 0.3

NG= 0.95

Sw= 0.13

Oil formation volume factor is already calculated in the work done before. The oil column calculated at each level is shown in Table 3.9:

Table 3.9

Calculated oil column at different levels.

Pressure (psi)	Rs (scf/stb)	Bo	Oil column (cm)
4934	984	1.411	1920
4738	937	1.403	1850
4543	891	1.394	1780
4347	845	1.385	1710
4152	799	1.376	1640
3956	754	1.367	1570
3760	709	1.358	1500
3565	665	1.349	1430
3369	621	1.339	1360
3174	578	1.329	1290

Table 3.9 (Continued).

2978	536	1.319	1220
2782	493	1.309	1150
2587	452	1.299	1080
2391	411	1.288	1010
2196	371	1.277	940
2000	331	1.266	870

It is shown, in Table 3.9, that oil column decreased from 1920 cm to 870 cm due to pressure, time and gas-oil ratio decrease.

Buoyancy Changes Due to Time, Pressure, And Gas-Oil Ratio

Buoyancy values are calculated at each different level using the Equation 3.10:

$$\mathcal{P}b = (pw - po) * ho * g \tag{3.10}$$

Where:

Pb= Buoyancy pressure (g/cm^2).
Pw= water saturation (g/cc).
Po= Crude oil density (g/cc).
ho= Oil column (cm).
g= gravitational force constant (cm/sec^2).

Buoyancy pressure is calculated in the unit of (g/cm s^2) and then converted to psi. The calculated buoyancy values are shown in Table 3.10 as follows:

Table 3.10

Calculated Bo at different levels.

Buoyant pressure (g/cm s^2)	Buoyancy (psi)
290269	421
278598	404
267009	387
255502	371
244077	354
232735	338
221476	321
210298	305
199204	289
188191	273
177261	257
166414	241
155648	226
144965	210
134365	195
123847	180

Buoyancy versus crude oil density is shown in Figure 3.5:

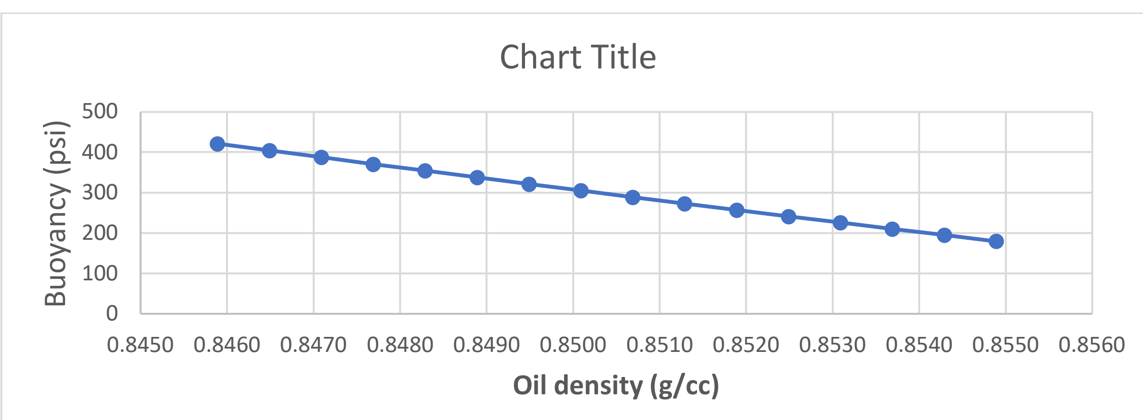

Figure 3.5. *Buoyancy vs crude-oil density.*

Depending on Table 3.10 and the graph in Figure 3.5, it is shown that buoyancy pressure decreased from 421 psi to 180 psi.

Buoyancy is affected more by gas-oil ratio than temperature change which means that gas lift is better than thermal well injection in this case in Trinidad reservoir and gas lift is applied.

Buoyancy Change Due to Gas Lift

Gas lift is applied in Trinidad reservoir with the following properties:

- Injection pressure: 1160.3 psi
- yg= 0.64
- The injection is able to increase the gas-oil ratio (GOR) by 250 SCF/STB

Reservoir properties before injection:

T=173 F

P= 2000 psi

yo= 0.64

The injection pressure is 1160.3 psi, So the injection will increase the well pressure from 2000 psi to 3160.3 psi.

Well-Pressure levels are assumed to increase equally from 2000 psi to 3160.3 psi. Well-temperature is assumed to be constant because gas-lift does not change reservoir or well temperature.

Solution Gas-Oil Ratio (Rs) Calculation Due to Gas-Lift

Solution gas-oil ratio (Rs) has been calculated where Rs will be increased by 250 SCF/STB, where the gas lift will increase it from 331 SCF/STB to 581 SCF/STB. Solution gas-oil ratio is calculated at each different pressure level to be sure of the value and the following values are obtained in Table 3.11:

Table 3.11

Calculated solution gas-oil ratio at different levels.

Pressure (psi)	**Rs (SCF/STB)**
2000	331
2077	347
2155	363
2232	378
2309	394
2387	410
2464	426
2541	442
2619	459
2696	475
2773	492
2851	508
2928	525
3005	541
3083	558
3160	575

The solution gas-oil ratio values are obtained using Equation 3.7 which is as follows:

$$Rs = y_g\left(\frac{p}{18}\,\frac{10^{0.0125\,(API)}}{10^{0.00091t}}\right)^{1.2048} \quad (3.7)$$

Where:

Rs= solution gas oil ratio (scf/STB).

P= Instantaneous pressure at a certain period (psi).

Yg= Gas specific gravity (g/cc).

t= temperature (F)

Table 3.11 shows that the gas-oil ratio increased from 331 SCF/STB to 575 SCF/STB.

Oil Formation-Volume Factor Calculation Due to Gas Lift

The oil formation-volume factor has been calculated at each different pressure and solution gas-oil ratio level. The calculation was done using Equation 2.3 which is as follows:

$$B_o = a_1 P^{a2} T^{a2} API^{a4} y_g^{a5} + a_6 \tag{2.3}$$

Where:

Bo= Oil formation volume factor (fraction).

P= pressure (psi).

T= Temperature (F).

Yg= Gas specific gravity (g/cc).

The list of values of coefficients Equation 2.3 is shown in the Table 3.12:

Table 3.12

List of coefficients values.

Coefficient	The Value
a_1	0.000005
a_2	0.639887
a_3	0.604183
a_4	0.961566
a_5	1.041364
a_6	1.079483

The calculated oil formation-volume factor at each different period is shown in Table 3.17.

Table 3.13

Calculated Bo at different levels.

Pressure (psi)	Rs (SCF/STB)	Bo
2000	331	1.266
2077	347	1.270
2155	363	1.275
2232	378	1.279
2309	394	1.283
2387	410	1.288
2464	426	1.292
2541	442	1.296
2619	459	1.301
2696	475	1.305
2773	492	1.309
2851	508	1.313
2928	525	1.317
3005	541	1.321
3083	558	1.325
3160	575	1.329

Table 3.13 shows that oil formation-volume factor increased from 1.266 to 1.329 due to well-gas lift.

Crude-Oil Density Calculation at Each Different Level

Crude oil density has been calculated at each different pressure, solution gas-oil ratio, and oil formation volume factor.

The calculation is done using Equation 3.10:

$$po = (62.42796 * yo + 0.0136 * yg * Rs)/Bo \quad (3.10)$$

Where:

Po= Oil density (lb/ft^3)/

yo= Oil specific gravity (g/cc)

yg= Gas specific gravity (g/cc)

Bo= Oil formation volume factor (fraction).

The calculated values are in the unit of lb/ft^3 and are converted to g/cc, where 1 lb/ft^3= 0.02 g/cc.

The calculated oil density values in lb/ft^3 and the converted ones to g/cc are shown in Table 3.14:

Table 3.14

Calculated crude-oil density at different levels.

Oil density due to GOR change (lb/ft3)	**Oil density (g/cc)**
53.358	0.8547
53.305	0.8538
53.255	0.8530
53.208	0.8523
53.164	0.8516
53.123	0.8509
53.084	0.8503
53.049	0.8497
53.015	0.8492
52.984	0.8487
52.956	0.8482
52.929	0.8478
52.905	0.8474
52.882	0.8471
52.862	0.8467
52.843	0.8464

Water density is given as 1 g/cc. In production engineering calculation, gas solubility change in formation water is usually neglected and water viscosity and density are assumed to be constant.

The gravitational force constant is given as 9.81 m/sec^2. But in the buoyancy equation, the gravitational force constant should be converted to cm/sec^2 which is equal to 981 cm/sec^2 and it is assumed constant with time.

Oil column is calculated at each different pressure, oil formation volume factor, and gas oil ratio.

The calculation was done based on the Equation 3.11:

$$OC = \frac{GRV * NG * \emptyset * (1 - Sw)}{Bo} \tag{3.11}$$

Where:

OC= Oil column (cm).

GRV= Gross rock volume (cm^2).

NG= Net to gross ratio

Por= Porosity (fraction).

Sw= Water saturation.

Bo= Oil formation volume factor (fraction).

Givens:

- GRV= 10900 cm^2
- Porosity= 0.3
- NG= 0.95
- Sw= 0.13
- Oil formation volume factor is already calculated in the work done before.

The oil column calculated at each level is shown in Table 3.15 as follows:

Table 3.15

Calculated oil column at different time levels due to gas lift.

Oil column (cm)	**Time (years)**
870	0.5
892	1
914	1.5
936	2
958	2.5
980	3
1002	3.5
1024	4
1046	4.5
1068	5
1090	5.5
1112	6
1134	6.5
1156	7
1178	7.5
1200	8

Buoyancy Pressure Change Calculation Due to Well-Gas Lift

Buoyancy values are calculated at each different level using Equation 3.12:

$$\mathcal{P}b = (pw - po) * ho * g \tag{3.12}$$

Where:

Pb= Buoyancy pressure (g/cm^2).

Pw= water saturation (g/cc).

Po= Crude oil density (g/cc).

ho= Oil column (cm).

g= gravitational force constant (cm/sec^2).

Buoyancy pressure is calculated in the unit of (g/cm s^2) and then is converted to psi. The calculated buoyancy values are shown in Table 3.16:

Table 3.16

Calculated buoyancy pressure at different levels.

Buoyant pressure (g/cm^2)	**Buoyancy (psi)**
124013	180
127898	186
131772	191
135634	197
139484	202
143321	208
147143	213
150951	219
154742	224
158517	230
162274	235
166013	241
169732	246
173433	252
177113	257
180771	262

Oil density versus pressure is shown in Figure 3.6:

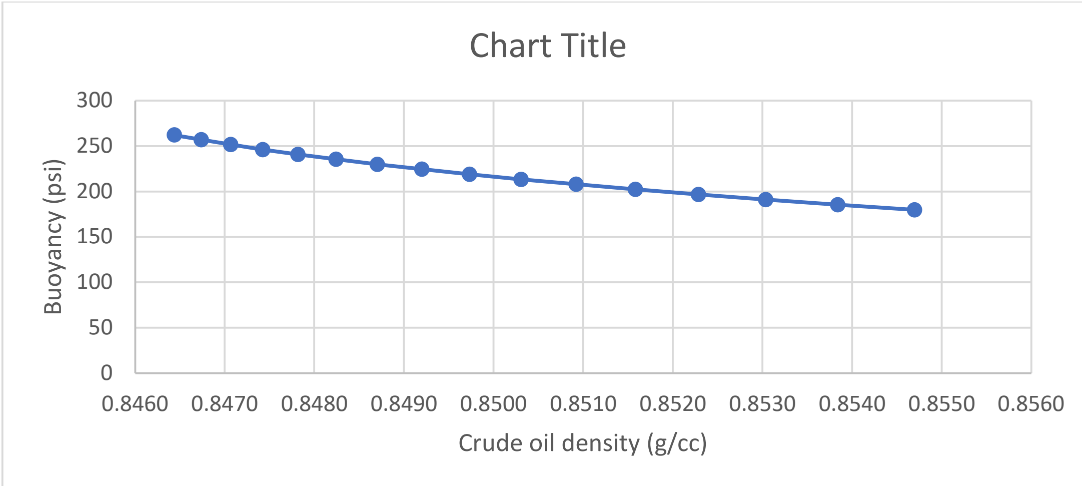

Figure 3.6. *Oil density vs pressure.*

It is shown that due to the gas-lift with such condition, the buoyancy pressure increased from 180 psi to 262 psi.

CHAPTER IV
Findings and Discussion

The study is done on Trinidad reservoir to understand buoyancy behavior in two changing conditions:

1. Depth, pressure, and temperature
2. Time, pressure, and gas-oil ratio

- ✓ **First condition study:** During the 1st condition study, the study was based on depth from reservoir depth to surface depth where the pressure decreases from reservoir depth (4934 psi) to surface depth (14.7 psi).Temperature, depth, pressure, crude-oil density, gravitational force constant, water density, temperature gradient, pressure gradient, and oil column values were calculated at each different level from reservoir depth to surface depth as shown in the above work (METHODOLOGY CHAPTER).Buoyancy is then calculated at each different level using the above-calculated parameters. The work is done using excel program Table 4.1 and graph in Figure 4.1 are obtained:

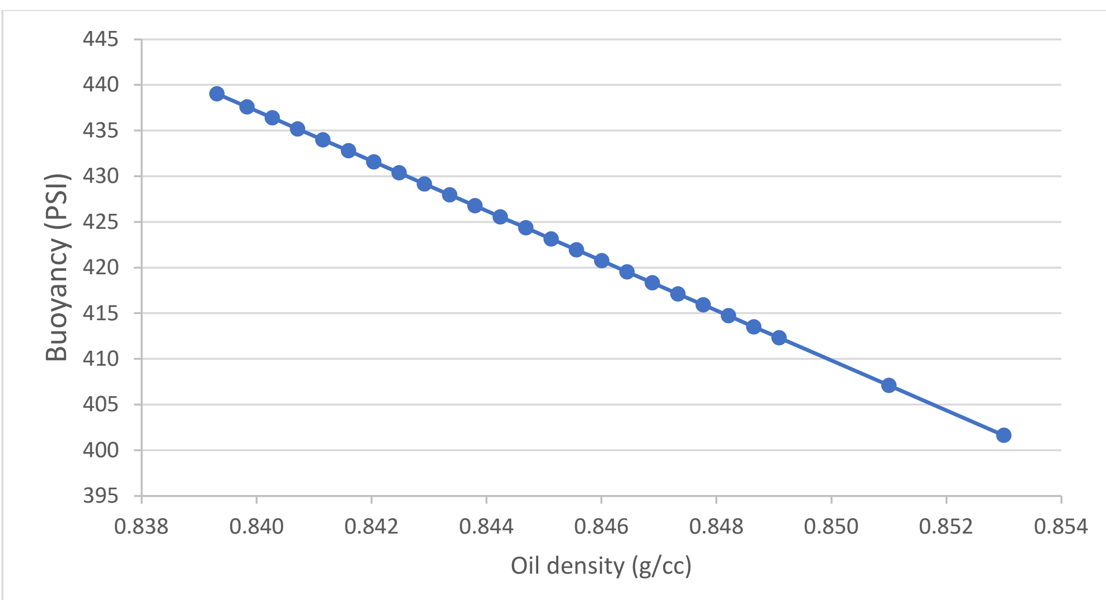

Figure 4.1. *Buoyancy vs crude-oil density.*

Table 4.1

Calculated buoyancy at different levels in the first condition.

Buoyancy (PSI)	**Temperature (ºF)**
439	173
438	169
436	166
435	162
434	158
433	154
432	150
430	146
429	142
428	138
427	135
426	131
424	127
423	123
422	119
421	115
420	111
418	107
417	104
416	100
415	96
414	92
412	88
407	84
402	80

Table 4.1 and graph 4.1 show that due to the first condition study (depth, pressure, and temperature change): buoyancy pressure decreased from 439 psi to 402 psi.

- ✓ **Second condition study:** During the 2nd condition study, the study was based on (time, gas-oil ratio, and pressure). Pressure, gas-oil ratio, crude oil density, water density, gravitational force constant, and oil column were calculated at each period.

Buoyancy is then calculated at each level as it is shown in the METHODOLOGY chapter.

The calculated buoyancy values are shown in Table 4.2 and Figure 4.2:

Table 4.2

Calculated buoyancy at different GOR levels in the second condition.

Buoyancy Pressure (psi)	**Rs (scf/STB)**
421	984
404	937
387	891
371	845
354	799
338	754
321	709
305	665
289	621
273	578
257	536
241	493
226	452
210	411
195	371
180	331

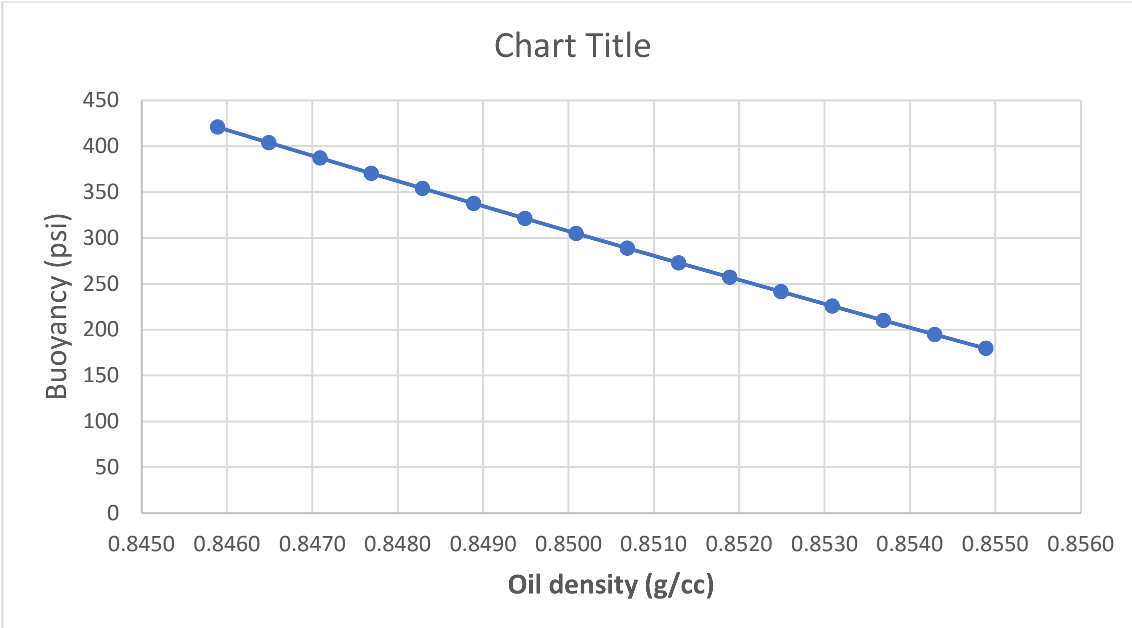

Figure 4.2. *Buoyancy vs crude-oil density.*

Table 4.2 and the graph in Figure 4.2 above show that buoyancy decreased from 421 to 180 due to the main factor of gas-oil ratio.

This means that gas-oil ratio has a higher impact on buoyancy pressure in the well than the temperature effect on buoyancy.

Depending on what came in previous studies, increasing gas-oil ratio affects buoyancy more than temperature.

Therefore, gas-lift to the well is better than well thermal injection to increase well head pressure, where well head pressure is presented mainly by buoyancy.

Well-head pressure is the pressure responsible to bring oil to the surface without artificial lift.

Well-head pressure= Reservoir pressure – Hydrostatic pressure + external pressure interventions.

Increasing buoyancy due to gas-lift means increasing the pressure in the well and thus a higher well pressure which leads to a better production with lower cost and time.

CHAPTER V
Conclusions and Recommendations

Conclusions

To sum up, buoyancy pressure change is equivalent to the gas-oil ratio and opposite to crude-oil density change. Moreover, Buoyancy pressure can be controlled through some artificial lift types, but the control is more useful in the well than that in the reservoir regarding buoyancy. The main factors affecting buoyancy are Temperature, ratio of gas to oil, pressure, and formation volume factor (Bo). Also, the temperature effect on buoyancy pressure in the well is lower than the effect of ratio of gas to oil on it. It is revealed that increasing gas-oil ratio is a better way to improve buoyancy pressure in a well. Both, gas lift and thermal injection in a well, improves buoyancy but gas lift is a better artificial lift method. Increasing buoyancy means improving well head pressure and thus having better production with lower cost

Recommendations

Another research can be done to understand the behavior of buoyancy and well-head pressure in the case of chemical injection to the well, where chemical injection improves the primary fluid quality or to enhance the flow of primary fluid. This process helps in the improvement in the production capacity, efficiency and reduction in the downtime.

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Appendices

Appendix A

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Supervisor: Prof. Dr. Salih SANER

Signature: ___________________

Appendix B

Ethical Approval Letter

YAKIN DOĞU ÜNİVERSİTESİ

ETHICAL APROVAL DOCUMENT

Date: 08/September/2022

To the **Institute of Graduate Studies**

The research project titled "**WELLBORE BUOYANCY VARIATIONS DURING THE LIFE OF A RESERVOIR**'' has been evaluated. Since the researcher will not collect primary data from humans, animals, plants or earth, this project does not need through the ethics committee.

Title: Prof. Dr.

Name Surname: Salih SANER

Signature:

Role in the Research Project: Supervisor