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Defended by:

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- TITLE-

Impact of the WAG Injection on the ultimate oil recovery factor.

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First of all, we thank God Almighty the Creator,

Who made our path easier and gave us the perseverance

To do this humble work. Praise be to God, by whose praise the blessings and

Righteous deeds have been achieved.

As the Prophet, may God's prayers and peace be upon him, said:

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Aya Kheloufi

Dedication

I dedicate this work to:

my mother who supported and encouraged me during these years of study without forgitting my dear father and my lovely sister Nassima; my brothers Abu baker, Younes and Abd el-karim to all my friends and who know's me spacialy to my best persone Husseine .

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This effort is dedicated to my mom and dad who have provided me the support and my sisters ; Sara , Bouchra, Nour , and my beloved little brother Seif , and to everyone who helped me.

MY LOVE

Aya kheloufi

Abstract: The Water Alternating Gas (WAG) process is a cyclic method of injecting gas followed by water and repeating this process over several cycles. The main purpose of WAG injection is to improve oil recovery, by increasing both macroscopic and microscopic sweep efficiency and to help maintain the reservoir pressure. In addition, the impact of water alternating gas (WAG) injection on ultimate oil recovery is significant. Due to the WAG postponing the gas breakthrough. Moreover, its process provides mobility control in fast zones which extends gas project life and oil recovery. the key parameters that affect WAG injection are the WAG ratio, cycle time, slug size, rock fluid properties ... etc. as WAG injection offers high fluid efficiency, is compatible with certain reservoir types, and has lower operational costs compared to other EOR methods. as an example (chapter IV) compared the Water Alternate Gas (WAG) and the Water Huff n Puff techniques for oil recovery in a tight oil reservoir, based on their effectiveness, their recoveries, as well as assessing the factors that affect the recovery based on both of the techniques. The result showed that Water Alternating Gas (WAG) has better results than using a Water Huff and Puff method

Keywords: Enhanced oil recovery (EOR), WAG injection, mobility, Displacement efficiency.

ملخص عملية الغاز بالتناوب المائي (WAG) هي طريقة دورية لحقن الغاز متبوعًا بالماء وتكرار هذه العملية على عدة دورات. الغرض الرئيسي من حقن WAG هو تحسين استخلاص الزيت، عن طريق زيادة كفاءة المسح العياني والمجهري والمساعدة في الحفاظ على ضغط الخزان. بالإضافة إلى ذلك، فإن تأثير حقن الغاز المتناوب بالماء (WAG) على الاستخراج النهائي للنفط كبير. بسبب تأجيل WAG لاختراق الغاز. علاوة على ذلك، توفر عمليتها التحكم في التنقل في المناطق السريعة التي تطيل من عمر مشروع الغاز واستعادة النفط. المعلمات الرئيسية التي تؤثر على حقن WAG هي نسبة WAG، ووقت الدورة، وحجم البزاقة، وخصائص سائل الصخور ... إلخ، حيث يوفر حقن WAG كفاءة عالية للسوائل، ومتوافق مع أنواع معينة من الخزانات، وله تكاليف تشغيلية أقل مقارنةً بالاستخلاص المعزز للنفط (EOR) الأخرى طُرق. كمثال (الفصل الرابع) مقارنة بين تقنيات الماء البديل (WAG) وتقنيات Water Huff n Puff لاستعادة النفط في مكمن نفط محكم، بناءً على فعاليتها، واستردادها، وكذلك تقييم العوامل التي تؤثر على الاستعادة القائمة على كلا التقنيتين. أظهرت النتيجة أن الغاز المتناوب بالماء (WAG) له نتائج أفضل من استخدام طريقة (Water Huff and puff) .

الكلمات المفتاحية: الاستخلاص المعزز للنفطEOR، حقن WAG، التنقل، كفاءة الإزاحة.

Résumé : La technique Water Alternating Gas (WAG) est une méthode cyclique d'injection de gaz suivie d'eau et de répétition de ce procédé sur plusieurs cycles. L'objectif principal de l'injection WAG est d'améliorer la récupération d'huile, en augmentant l'efficacité de balayage macroscopique et microscopique et d'aider à maintenir la pression du réservoir. De plus, l'impact de l'injection de gaz à alternance d'eau (WAG) sur la récupération finale du pétrole est important. En raison du report de la percée du gaz par le WAG. De plus, son procédé offre un contrôle de la mobilité dans les zones rapides, ce qui prolonge la durée de vie du projet gazier et la récupération du pétrole. Les paramètres clés qui affectent l'injection WAG sont le rapport WAG, le temps de cycle, la taille du slug, les propriétés du fluide rocheux, etc. car l'injection WAG offre une efficacité élevée du fluide, est compatible avec certains types de réservoirs et a des coûts opérationnels inférieurs par rapport à d'autres EOR méthodes. À titre d'exemple (chapitre quatre) a comparé les techniques (WAG) et Water Huff n Puff pour la récupération de pétrole dans un réservoir de pétrole étanche, en fonction de leur efficacité, de leurs récupérations, ainsi que de l'évaluation des facteurs qui affectent la récupération en fonction sur les deux techniques. Le résultat a montré que le gaz alterné à l'eau (WAG) a de meilleurs résultats que l'utilisation d'une méthode Water Huff and Puff.

Mots-clés : Récupération assistée du pétrole (EOR), injection WAG, mobilité, efficacité de déplacement

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ABBREVIATIONS AND NOMENCLATURE

EOR	*Enhanced Oil Recovery.*
WAG	*Water alternating gas.*
SWAG	*Simultaneous Water-Gas injection.*
HWAG	*Hybrid Water Alternating Gas.*
CWAG	*Chemically WAG Injection.*
FAWAG	*Foam Assisted Water Alternating Gas.*
IWAG	*Immiscible Water Alternating Gas.*
λ	*the mobility of a fluid.*
k	*permeability.*
L	*Length.*
A	*Area.*
ΔP	*Pressure difference.*
μ	*Viscosity.*
ρ	*Fluid density.*
PV	*Pore volume.*
RF	*Recovery factor.*
M	*Mobility ratio.*
S_{orWAG}	*Residual oil for WAG.*
S_{orw}	*Residual oil for water.*
S_{org}	*Residual oil for gas.*
WCT	*water cut.*
GOR	*Gas-Oil Ratio.*
HCg	*Hydrocarbon gas.*
IFT	*Interfacial Tension.*

k_h	*Horizontal Permeability.*
k_{rg}	*Gas Relative Permeability.*
$k_{rg,max}$	*Gas Relative Permeability at Maximum Gas Saturation.*
k_{ro}	*Oil Relative Permeability.*
$k_{ro,max}$	*Oil Relative Permeability at Maximum Oil Saturation.*
k_v	*Vertical Permeability.*
k_{rw}	*Water Relative Permeability.*
$k_{rw, max}$	*Water Relative Permeability at Residual Oil Saturation.*

INTRODUCTION

GENERAL INTRODUCTION:

Enhanced Oil Recovery (EOR), across all petroleum fields, has garnered a lot of attention over the past years. As oil reserves are increasingly depleted by improved oil extraction methods. However, the challenge of lower returns from traditional techniques remains. The primary method of obtaining oil from a reservoir is the water injection process, and it is considered the least preferred method due to the large amount of oil remaining in the rock. As these reservoirs age, the natural pressure that facilitated oil production decreases, making it increasingly difficult to extract the remaining hydrocarbons. results? Valuable reserves remain trapped deep in reservoirs, out of reach using conventional methods alone. This predicament is exacerbated by reservoir heterogeneity, where differences in rock properties create complex flow patterns that impede fluid movement. In addition, unfavorable flow ratios between the injected fluids and the target oil lead to displacement, in which the injected fluids bypass areas of the oil, leaving behind large amounts of unrecovered oil.

Enhanced Oil Recovery (EOR) refers to any reservoir process used to alter the existing rock/oil/brine interactions (fluid/liquid interaction; fluid/rock interaction) in the reservoir in order to increase oil recovery, and such interaction may result in reduced surface tension, swelling oil, reduce oil viscosity; also modulating wettability (Don W. Green et al., 1998). EOR has a lot of methods and each method has its own considerations for its use. But all these methods aim to improve the recovery factor and accelerate the rate of oil production. One of the EOR methods is the water alternating gas (WAG) process that combines the advantages of two conventional methods including WF and Gas Injection (GI). Hence, the enhancement of macroscopic sweep efficiency in WF operation and high displacement efficiency in the gas injection process are involved in WAG to improve incremental oil production. In the case of alternating injection of water after gas, water (because of its higher density) will sweep the bottom part of the reservoir and will stabilize the displacing front by creating a more favorable mobility ratio.

This technique is profitable in terms of economic perspective by lowering the gas volume required to be injected into the reservoir.

WAG injection has been applied since the early 1960s. The first field application of the WAG process took place in the North Pembina field in Alberta, Canada, in 1956-7. Since then, WAG injection has been applied with success in most field trials. The majority of the fields were located in Canada and the USA. Recently been widely used worldwide because it has been proven that WAG injection is a better method than gas injection and water injection. In terms of economic evaluation, gas injection is an expensive operation; therefore, WAG is a better method to be implemented because the amount of gas injected in WAG is less than the amount of gas injected in continuous gas injection. (Mohammad and Mahmoud 2018).

Our project stands on simulation cases of fields where water alternating gas is applied as a chosen EOR technique to maximize the ultimate oil recovery against estimated reserves in place. Choosing WAG injection as a potential solution for enhanced oil recovery offers several advantages and benefits. The key reasons for selecting WAG injection:

Increased Sweep Efficiency: One of the main goals of WAG injection is to improve the sweep efficiency of the injected fluids in the reservoir.

By alternating injections of water and gas, the fluids can reach and displace oil in different regions of the reservoir, improving the overall recovery of oil, Gas Mobility Control, Viscosity Control, Pressure Maintenance, Field Proven Success, and Environmental Considerations: WAG injection can have environmental benefits that can contribute to the economic value of the project. For example, the injection of carbon dioxide (CO_2) in WAG injection can help sequester greenhouse gases underground, thereby reducing carbon emissions.

The aim of this thesis is to focus on the impact of WAG injection on the ultimate oil recovery. Firstly, **chapter one** includes a “literature review" about the EOR background and water alternating gas process description, **second chapter** investigates Factors affecting WAG injection performance by choosing categories which are rock properties, fluid properties, and rock-fluid properties. We selected for each category, a specific parameter to see their effect on the WAG injection recovery factor. **Chapter three** focuses on operational conditions including WAG ratio, WAG cycle time, number of cycles, slug size, and first phase injected. **The fourth chapter** compares WAG Injection with other recovery methods.

CHAPTER I:

LITERATUR REVIEW

I.1. EOR Background

Enhanced oil recovery (EOR) methods, also referred to as tertiary oil recovery methods, and are employed when primary and secondary recovery methods do not improve the production from brownfields. Thus, almost more than 60% of the oil initially in place (OIIP) remains in the reservoir.

1.1. EOR and IOR definition:

Enhanced oil recovery (EOR) is defined as "the recovery of oil by injection of a fluid that is not native to the reservoir." EOR is a means to extend the productive life of depleted and uneconomic oil fields. It is usually practiced after recovery by other, less risky, and more conventional methods, such as pressure depletion and water flooding, have been exhausted. When primary and secondary recoveries start to deplete, we go towards the Enhanced Oil recoveries methods. Not all reservoirs are amenable to EOR. Effective screening practices must be employed to identify suitable candidates. As part of the screening, discounted cash-flow projections are routinely performed to assess profitability. At the core of these projections is an estimate of recovery performance. In the initial screening studies, invariably, performance predictions from numerical simulation studies are not yet available.

Therefore, other methods usually empirical are needed to estimate future performance.

❖ We have also another definition of EOR:

The Society of Petroleum Engineers or SPE (SPE E&P Glossary, 2009) offers the following definitions:

1. Improved oil recovery, or IOR, is “any of various methods, chiefly reservoir drive mechanisms and enhanced recover(y) techniques, designed to improve the flow of hydrocarbons from the reservoir to the wellbore or to recover more oil after the primary and secondary methods (water- and gas floods) are uneconomic.”

2. Primary oil recovery is “the amount of the reserves recovered by primary production—that is, without injected fluid pressure support.”

3. Secondary oil recovery is “a recovery improvement process such as water flooding or gas flooding.”

4. Enhanced oil recovery, or EOR, is “one or more of a variety of processes that seek to improve the recovery of hydrocarbon from a reservoir after the primary production phase.[1]

2.2. EOR Methods Description:

The following are the widely accepted EOR methods:

A-Thermal:

This includes steam stimulation; steam flooding; steam-assisted gravity drainage (SAGD); and in situ combustion or, in contemporary terms, air injection. Other current noncommercial technologies include electromagnetic heating from resistive heating at low frequencies to inductive and dielectric heating at higher frequencies, including microwave radiation.

B-Chemical:

This family of methods generally deals with the injection of interfacial-active components such as surfactants and alkalis (or caustic solutions), polymers, and chemical blends. Surfactants for foam flooding come in several categories, including those intended for deep conformance in solvent flooding.

C-Miscible or Solvent Injection:

These methods are frequently associated with a form of gas injection using gases such as hydrocarbon gas (enriched or lean), carbon dioxide, and nitrogen. However, the solvent, though not necessarily economic, can be a liquid phase. Supercritical phases such as high-pressure carbon dioxide are good solvents. In modern enhanced oil recovery applications, co-injection of IOR or conformance agents, such as gels or foams, can be necessary. More recent developments include the injection of carbon dioxide-soluble surfactants to generate in situ foams for mobility control. Some EOR methods that have been extensively tried in the field include microbial-enhanced oil recovery that could fall in any of the aforementioned categories, but some of the mechanisms involved are not fully understood.[2]

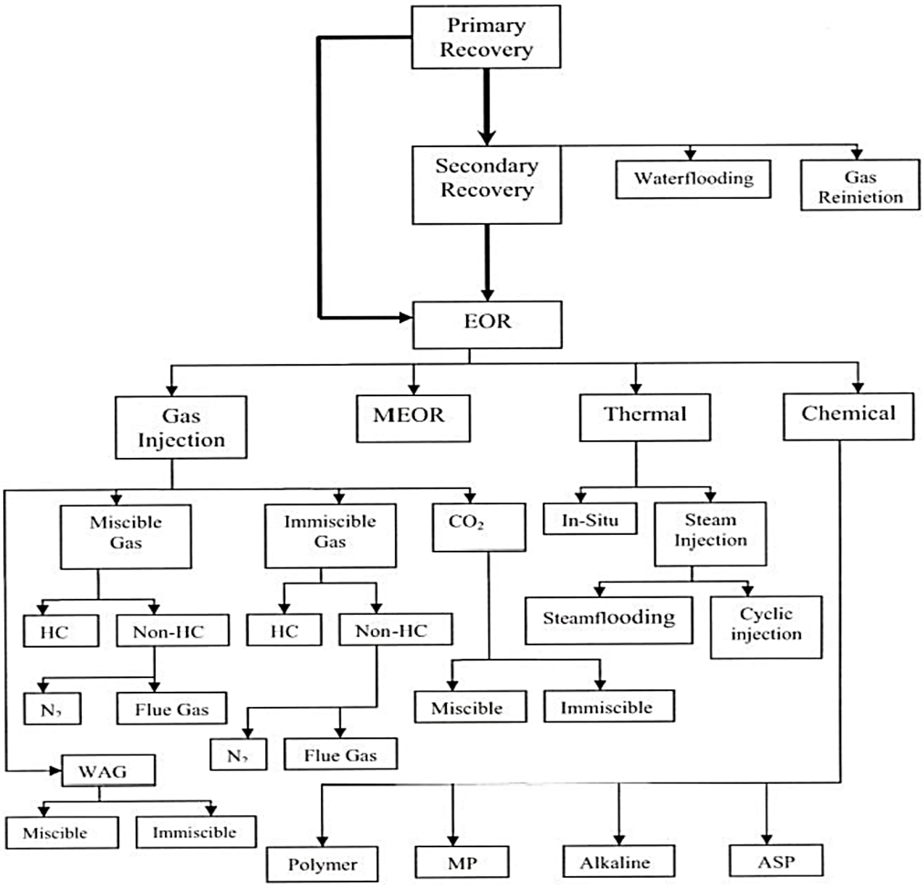


Figure I.1: Flow chart of oil recovery methods.

I.2. General Description related to injection

2.1. Recovery efficiency.

The main objective of tertiary recovery methods is to increase the overall displacement efficiency. Recovery efficiency is used to assess the performance of the injected fluid as a function of the amount of oil and gas that can be recovered. Recovery efficiency (ER) is a function of displacement efficiency (ED) and the volumetric scanning efficiency (EV). These two terms play an important role in the magnitude of the total recovery efficiency. **Equation (I.1)** shows that the efficiency of recovery is the product of recovery efficiency (ER) and displacement efficiency (ED). Displacement efficiency is often referred to as microscopic displacement while volumetric scanning efficiency is referred to as macroscopic displacement. (Lake, 1989).

$$ER = ED.EV \qquad \text{(I.1)}$$

2.2. Viscous fingering and mobility ratio.

Mobility of a phase is defined as the ratio of its effective permeability to the viscosity of that phase: The mobility of a fluid (λ), permeability (k) and viscosity (μ)

$$\lambda = \frac{k}{\mu} \qquad (I.2)$$

Mobility ratio M, on the other hand, is the ratio of the mobility of the displacing fluid (injectant) to the mobility of the displaced fluid:

$$M = \frac{\left(\frac{k}{\mu}\right)\text{displacingfluid}}{\left(\frac{k}{\mu}\right)\text{displacing fluid}} \qquad (I.3)$$

From **equation (I.3),** it is clear that when a gas or other less viscous fluid is injected as displacing fluid to displace oil (a more viscous fluid) in the reservoir, the mobility ratio is higher than 1. The gas with higher mobility will finger through (or channel through) the oil, leading to early gas breakthrough and lower recovery (Christle et al., 1991). This had been reported in the many published literatures, for example in Adena, Granny's Creek, and Lick Creek (Christensen et al., 2001). In the opposite scenario where fluid of less mobility is injected to displace the oil, the mobility ratio is less than unity, and the displacing fluid will act as if it is a physical piston which displaces the oil in the reservoir. **Figure (I.2)** shows how the mobility ratio affects the stability of a displacement.[3]

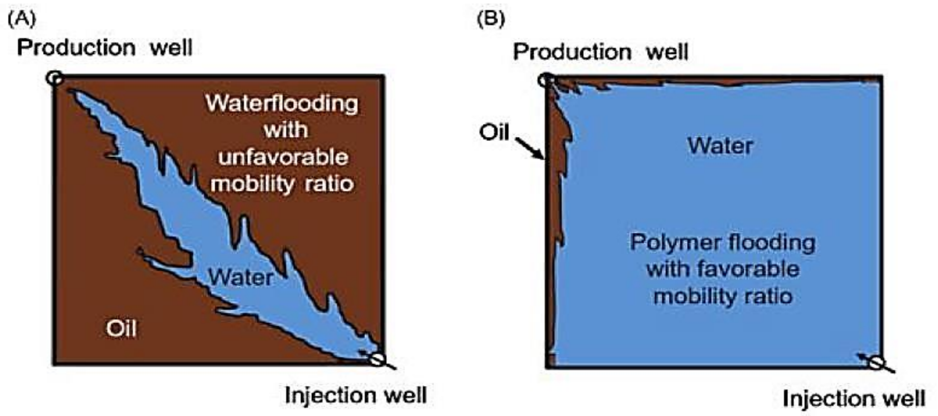


Figure I.2: Phenomenon of viscous fingering.

I.3. Water Alternating Gas (WAG)

3.1. WAG process:

Water alternating gas (WAG) injection is a tertiary oil recovery technique and is a combination of two traditional technologies - Water flooding and gas injection. The WAG injection was originally proposed as a method to improve the sweep of gas injection, mainly by using the water to control the mobility of the displacement and to stabilize the front. Because the microscopic displacement of the oil by gas is normally better than by water, the WAG injection combines the improved displacement efficiency of the gas flooding with an improved macroscopic sweep by water injection. This has resulted in improved recovery compared to pure water injection. It also improves the economy by reducing the volume of gas that needs to be injected into the reservoir.[4]

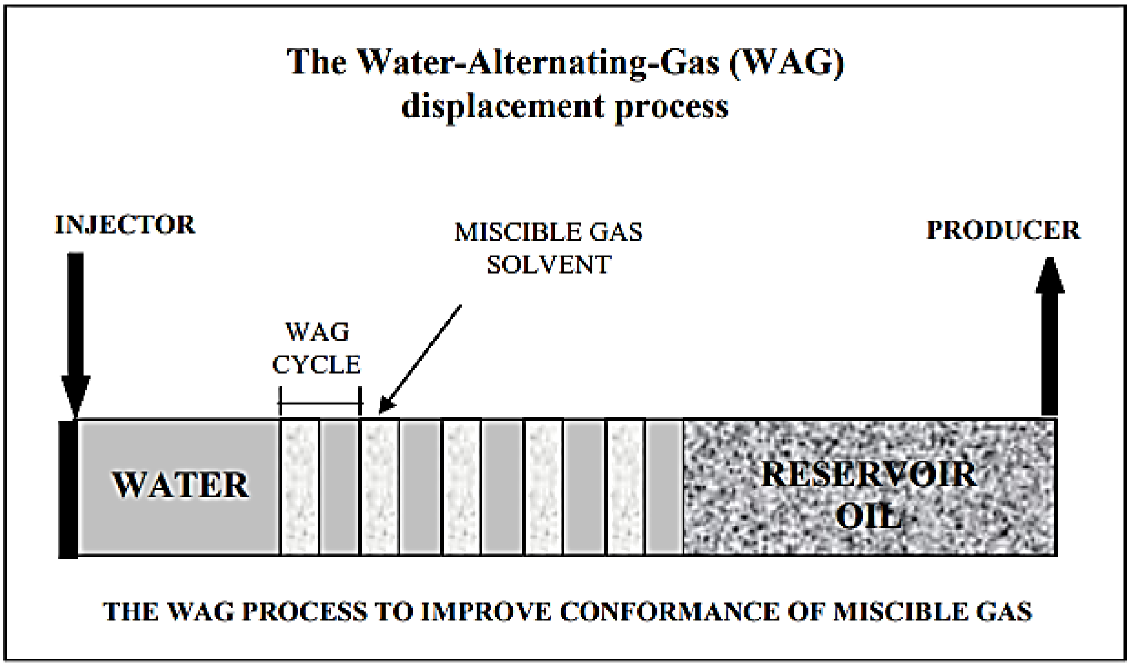


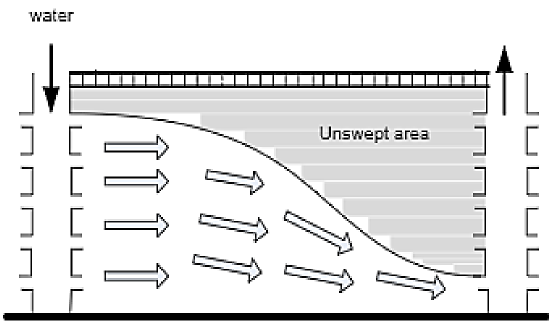
Figure I.3: Schematic of the Water-Alternating-Gas Process.

3.2. The main purpose of The WAG Injecting.

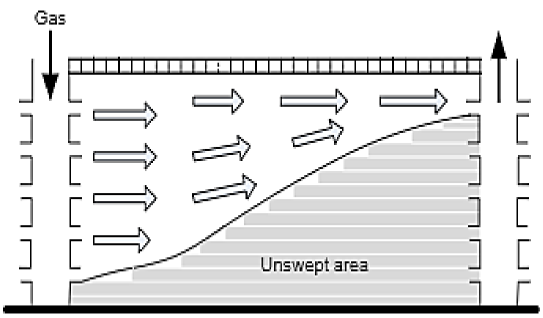
Under the condition of miscibility, the interfacial tension will decrease between the residual oil and the injected gas, therefore, the oil will swell and a single phase will be created, which facilitates the displacement of the remaining oil. The part of the oil that remains composed of very heavy hydrocarbon molecules is called residual saturation during the injection of the fluids.

Miscible ($Sorm$) When the injection of gas continues, the gas begins to move the miscible part, this process of moving is very efficient. A second water injection after the gas injection will act as a piston to advance the miscible plug, increasing microscopic efficiency.

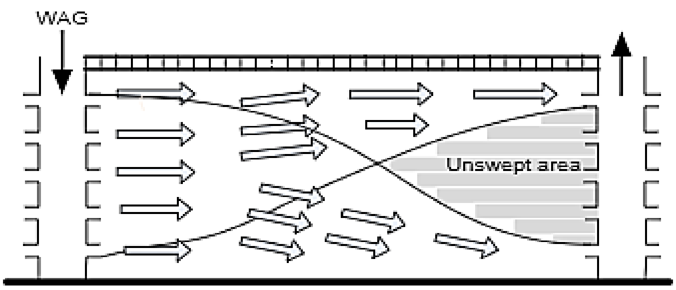
WAG injection is also used to increase the amount of oil contacted compared to water injection alone. In a high permeability sandstone reservoir, gravity segregation is common; therefore, gas will tend to move to the top of the reservoir and dense water will tend to migrate to the bottom of the reservoir. Therefore, using WAG injection, the top of the tank can be brought into contact with the injected gas and the water will push the miscible slug. This will increase microscopic efficiency as the un-swept reservoir area will be smaller. Moreover, residual oil for WAG is lower than residual oil for water and residual oil for gas ($SorWAG< Sorw$; $Sorg$). The combination of the improvement of the microscopic displacement efficiency of the injected gas and the improvement of the macroscopic displacement efficiency by the injection of water makes it possible to obtain better oil recovery. (Samba, 2015) (Afzal et al., 2020) (Abdullah & Hasan, 2021).



The gravity effect during the Water injection.



The gravity effect during the gas injection.



The gravity effect during the WAG injection.

3.3. Types of WAGI.

WAG processes can be grouped in many ways. The most common is to distinguish between miscible and immiscible displacements as a first classification:

a) Miscible WAG.

It is difficult to distinguish between miscible and immiscible WAG. In many cases, multi-contact gas-oil miscibility may have been obtained, but a lot have been performed on a close well spacing, but recently miscible processes have also been tried out even at offshore-type well spacing.

b) Immiscible WAG.

This type of WAG process has been applied with the aim of improved frontal stability or contacting un-swept zones. Application has been in reservoirs where gravity-stable gas injection cannot be applied because of limited gas resources or the reservoir properties like; the low dip of strong heterogeneities. In addition to sweeping, the microscopic displacement efficiency may be improved as well. Residual oil saturation is generally lower for WAG than for a Water flood and sometimes even lower than a gas flood, due to the effect of three-phase- and cycle-dependent- relative permeability. Sometimes the first gas slug dissolves to some degree into the oil.

This can cause mass exchange (swelling and stripping) and a favorable change in the fluid viscosity or density relations at the displacement front. The displacement can then become near miscible.

c) Hybrid WAG.

Hybrid WAG uses a first large slug of gas injected instead of water followed by a number of small slugs of water and gas in the process. The result of the field test is quite similar to the miscible WAG process.

d) Simultaneous Water-Gas injection (SWAG).

Uncertainty remains about the actual displacement process. It has not been possible to isolate the degree of compositional effect on oil recovery by WAG. Miscible projects are mostly found onshore and the early cases used expensive solvents like propane, which seem to be a less economically favorable process at the current time. Most of the miscible projects reviewed are depressurized in order to bring the reservoir pressure above the minimum miscibility pressure (MMP) of the fluids. Since failure to maintain sufficient pressure, means loss of miscibility, real field cases may oscillate between miscible and immiscible gas during the life of the oil production. Most miscible WAG.[5]

e) Foam Assisted Water Alternating Gas (FAWAG) process.

FAWAG is usually introduced in reservoirs with WAG already in use. FAWAG can be intended to create a foam barrier that impedes the upward passage of the gas; forcing it spread laterally and in the process contact previously upswept parts (Saleem, Q, et al., 2012). This method is more effective when the vertical permeability is so high, thus the foam will make a barrier to prevent gas segregation. **Figure I.4** shows how the FWAG can improve the oil recovery factor.

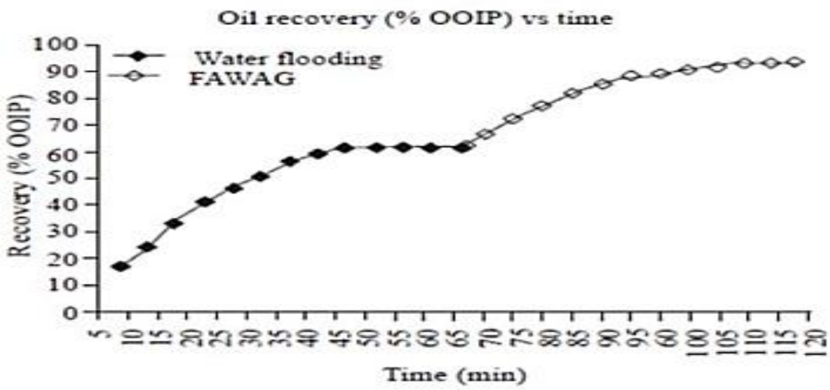


Figure I.4: Oil recovery after FAWAG application (Saleem, Q, et al., 2012).

F) Chemically WAG Injection (CWAG).

Chemical Wag injection is a Chemical slug (mixture of alkaline, surfactant, and polymer) that will be injected during the WAG process to reduce interfacial tension (IFT) and improve the mobility ratio. In a CWAG process, a chemical slug is chased by water, preceded by a gas slug, and followed by alternate CO2 and water slug or chemical slug injects after one cycle of gas and water slug (Don W. Green et al., 1998).

3.4. Operational Requirements:

Required operational work is minimal but includes working over the injector well, flow line, and Christmas tree modifications.

The following show some aspects that must be considered before the WAG project operational implantation: Injectivity test at the wells, and test stimulation at the injectors. Evaluate the injection period required to carry out the injection taking into account the available injectivity test. For the project design need to consider additional gas facilities requirements, if the water injection rate is too low due to injectivity problems at the patterns located at low reservoir quality regions. Since in order to increase the reservoir pressure and drain the WAG project-associated reserves in a reasonable time, it will be necessary to increase the gas injection rate by pattern.[6]

The diagram shown in **Figure I.5** indicated the main changes required at the well injectors surface in order to control the water alternating gas injection process.

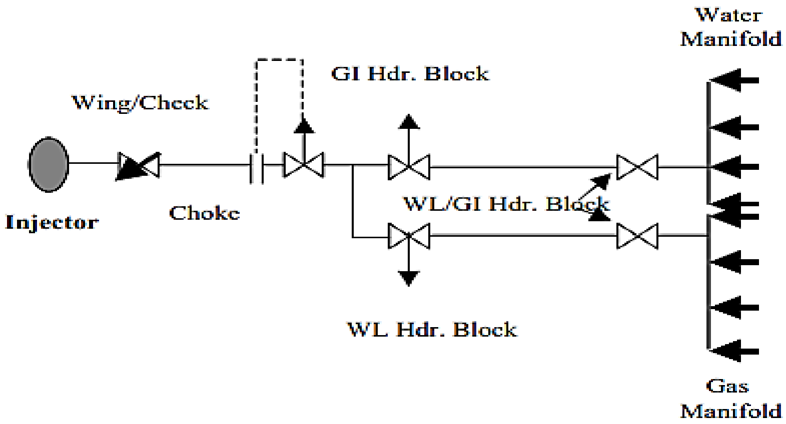


Figure I.5: Surface facilities for the WAG injection process.

3.5. PROBLEMS IN THE WAG PROCESS:

A problem of the WAG process is that the injected water blocks contact between the injected gas phase and the residual oil. The fields should have water and gas supplied for good economic consideration. Some operational problem cannot be avoided in the production life of an oil field. The WAG injection is more demanding than a pure gas or water injection since the injection need to be changed frequently. It is basically problems from the different fields. Some of the problems believed to have been most severe are discussed below.

a) Early breakthrough

In production wells Poor understanding of the reservoir or inadequate reservoir description can lead to unexpected events such as early gas breakthrough. Several field cases report early gas breakthroughs due to channeling or override. For offshore fields, an override can be very critical since the number of wells in the projects generally is very limited.

b) Reduced Infectivity

Reduced infectivity means less gas and water injected into the reservoir. This will cause a rapid pressure drop in the reservoir, which affects displacement and production.

c) Corrosion

Corrosion is a problem that needs to be solved in almost all WAG injection projects. This is mainly due to the fact, that the WAG injection normally is applied as a secondary or tertiary recovery method. The project will have to take over old injection and production facilities originally not designed for this kind of injection. These problems have in most cases been solved by the usage of high-quality steel (different kinds of stainless steel or ferritic steel), coating of pipes, and treatment of equipment.

d) Scale formation

The occurrence of scales in WAG field trials is usually and logically found when CO2 is the injected gas source. The scale formation may stress the pipelines and can lead to failure. In CO2 floods, casings many times have been coated with an extra layer for corrosion protection. This layer can be damaged by scale and corrosion (pitting) can occur. In worst cases, production stops have been needed either for chemical squeeze treatments or while repairing the damage.[7]

CHAPTER II:

Factors Affecting WAG Injection Process.

II. Factors affecting WAG injection:

It is very important to understand the performance parameters for WAG injection, because we have to know the effects of each parameter, that is will feed us by more understanding for WAG mechanism. The most important parameters for WAG design are rock proprieties; Fluid proprieties; Fluid-rock proprieties; Operational conditions (WAG ratio; WAG cycle time; WAG slug size; WAG cycle length; Selecting of the starting phase; WAG cycle number).

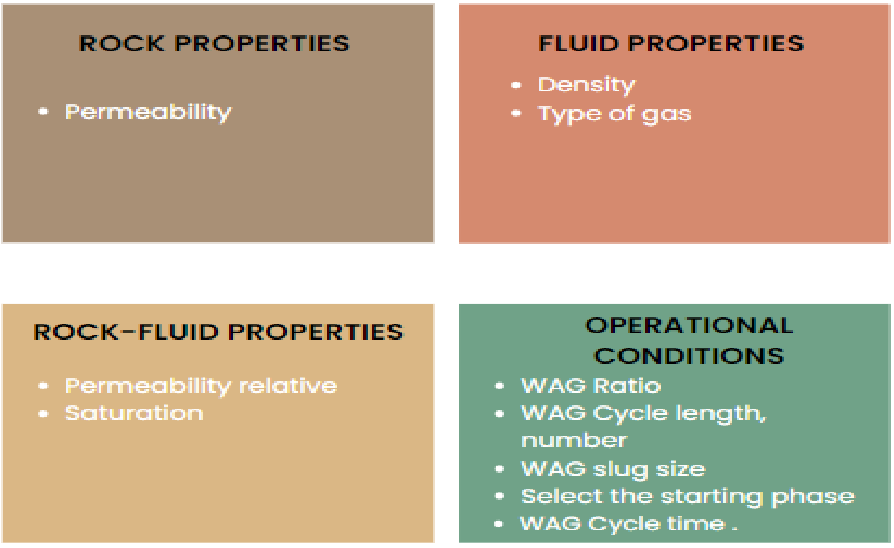


Figure II.1: schema of the Parameters affecting WAG recovery (Aya.K; Hadjer.K ;(2023))

II.1: Rock proprieties

1.1. Permeability

Permeability definition is the ability of a medium to transport fluids. In petroleum engineering, it refers to the ability of rock formation to transmit fluids (oil, gas & water).

This permeability ability somehow has a connection with porosity which is in terms of connected pores.

The mathematical formulation for permeability is called Darcy’s Law. It is defined as:

$$k = \frac{q\mu L}{A\Delta P} \qquad \text{(II.1)}$$

q = flow rate (cm3/s)

µ = viscosity (cP)

L = length (cm)

A = area (cm2)

Δ P = pressure difference (atm)

- **The effect of permeability on the oil recovery:**

Multiple research works demonstrated that reservoir permeability is one of the main factors controlling WAG performance. Yu et al. (2017) showed CO2–water alternating flooding experiment results which indicates that it is permeability that mainly impacts the displacement efficiency of CO2–EOR in low-permeability reservoir.[8]

Reservoir model input and selected parameters range for WAG recovery factor prediction:

Basic reservoir and fluid properties			
Reservoir		Fluid	
Rock	Sandstone	Crude oil type	Light oil
Porosity (fraction)	0.149	Oil gravity	Variable
Horizontal permeability (md)	Variable	Gas gravity	Variable
Vertical permeability (md)	Variable	Solution GOR (Sm3/Sm3)	Variable
Dimensions *XY* (m)	100 × 100	Oil viscosity (cp)	The function of oil gravity, gas gravity, initial solution GOR
Initial water saturation (fraction)	0.1	Gas viscosity (cp)	
Residual oil saturation to water (fraction)	0.25	Oil FVF (RB/STB)	
Residual gas saturation to gas (fraction)	Variable	Gas FVF (ft3/scf)	
Max trapped gas (fraction)	Variable	Oil and gas compressibilities (1/psi)	
Initial pressure (bar)	340	Water viscosity	Variable
Reservoir temperature (°C)	100	Water FVF (Rm3/Sm3)	1
Depth (m)	3000	Water compressibility (1/bar)	4.52E−5

Chart II.1: Reservoir model input data (Mousavi Mirkalaei, (2011, July)).

Input variable	Min value	Max value
Horizontal permeability (md)	50	1000
Permeability anisotropy (K_v/K_h)	0.01	1

Chart II. 2: The range used for horizontal and vertical permeabilities. The ranges were selected covering wia de range of oil field reservoirs (Mousavi Mirkalaei, (2011, July)).

Result:

- The effect of vertical segregation was studied by Jackson et al. (1985), which concluded that the relationship between permeability ratio and oil recovery rates is of inverse proportions also in this research study they observed that generally the higher the vertical permeability, the higher the field recovery factor under WAG injection.

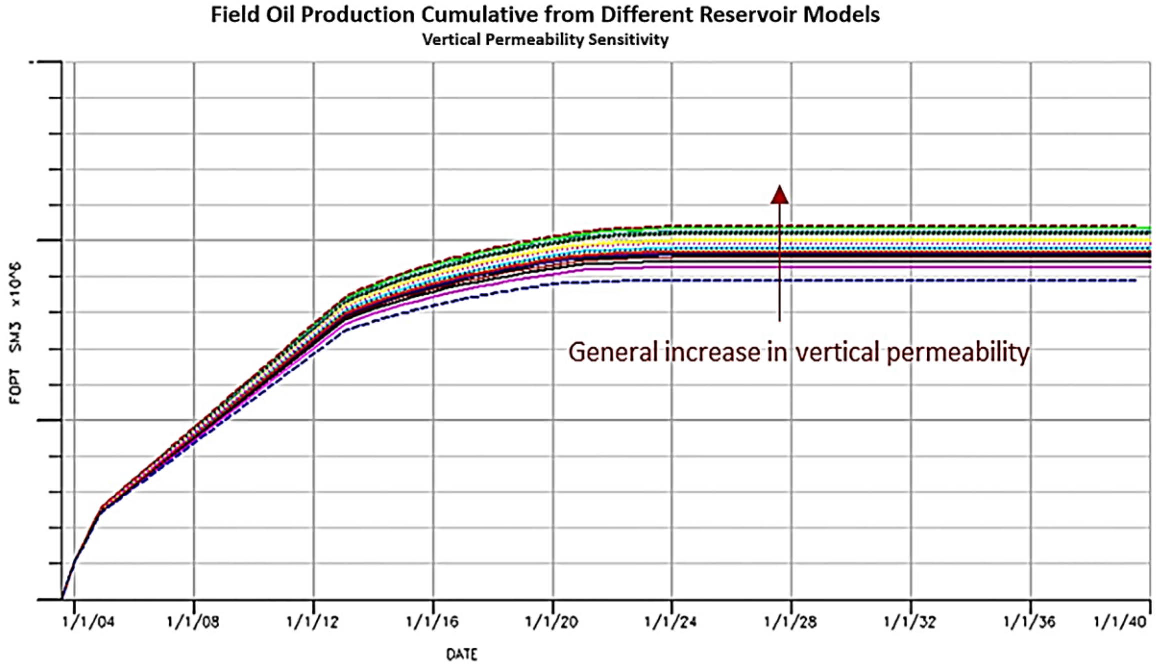


Figure II.2: Impact of reservoir vertical permeability on WAG recovery factor

(Mousavi Mirkalaei, (2011, July)).

- The simulation results from horizontal permeability sensitivity demonstrated that the higher the horizontal permeability, the higher the initial oil production rate under the WAG injection process; however, the ultimate WAG recovery factor might be lower with high permeability if the WAG process was not properly optimized. Gas override was one of the issues that lead to oil production loss with high gas–oil ratio (GOR) in this case.

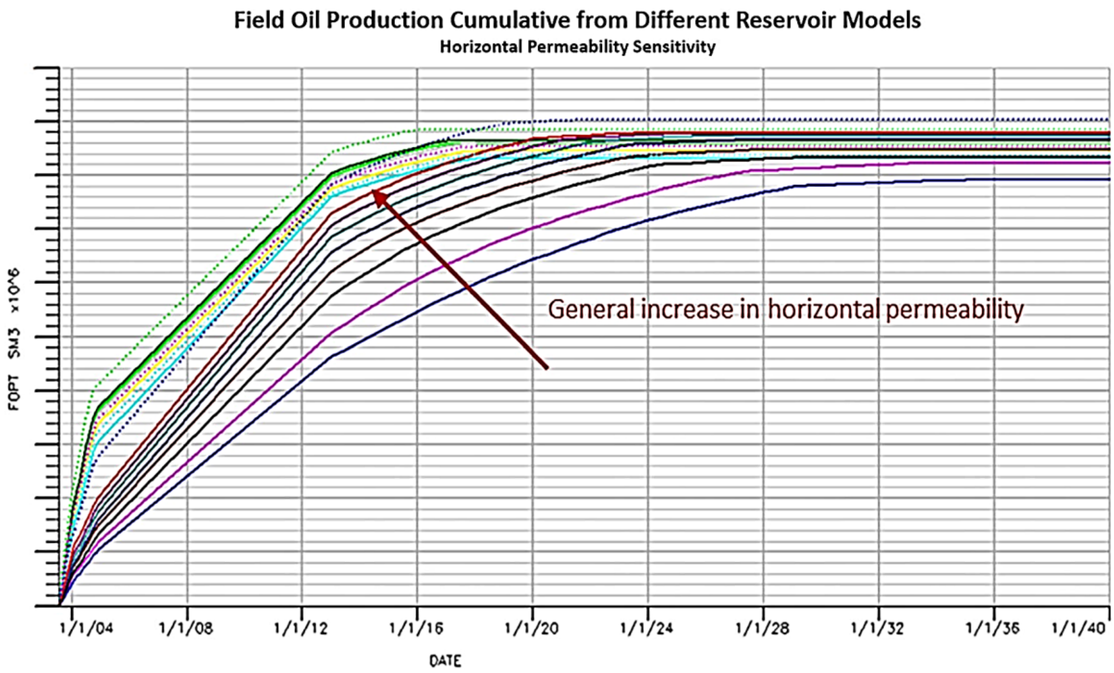


Figure II.3: Impact of reservoir horizontal permeability on WAG recovery factor.

(Mousavi Mirkalaei, (2011, July)).

II.2. Fluid proprieties

2.1. Oil density:

The density is known as the specific mass, is its mass per unit volume. Mathematically, density is defined as mass divided by volume. It was determined by using the equation below:

$$\rho = \frac{M1-M2}{V} \qquad \text{(II.2)}$$

Where ρ = Fluid density, g/cc; M1= Weight of pycnometer, g; M2 = Weight of the pycnometer with measuring fluid, g, and V = Volume of the measuring fluid, cc.

- **The effect of oil density on the WAG injection:**

The process of WAG can be classified into different forms by the methods of fluid injection. To investigate the effect of oil density **Anuar, N; and all** are used Immiscible Water Alternating Gas Flooding (IWAG) which is the process of WAG injection where the gas injected is not miscible with residual oil in the pore channels.[9]

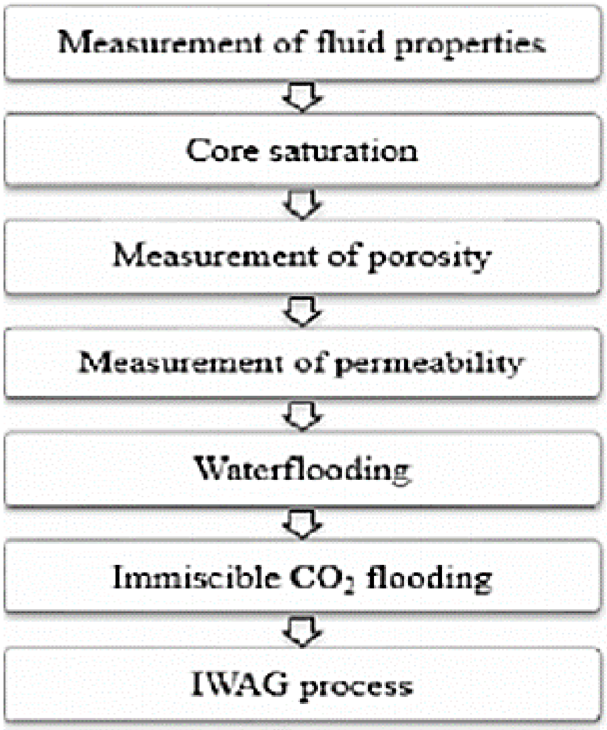


Figure II.4: Experimental Procedure in this study (Anuar, N., and all (2017)).

Result:

- **Figure II.5**: shows the relationship between three different oil densities and percentage recovery for water flooding, immiscible CO2 flooding, and IWAG flooding recorded at every 0.5 PV and a total of 2.5 PV for each type of flooding. During the water flooding process, the increment of oil recovery for each oil density was different. This is due to the different flow resistance of oil, which depends on density. From the graph, an oil density of 0.72 g/cc shows the highest incremental oil recovery compared to others because of its lowest density, and viscosity. At 2PV, oil recovery for all three IWAG ratios are relatively increasing with a constant rate because the water injected acts like a piston which evenly sweeps the front oil. At this time, maximum oil recovery was recorded. After 2PV, the graph is constant and there is no increase in oil recovery. This is due to the occurrence of gravity segregation where the injected water tends to flow at the bottom part of the model only. This occurs because the water has a higher density than oil. During immiscible CO2 flooding, the graph shows a slight increase in oil recovery which is only about 2% at 3.5 PV. This is due to the possibility of viscous fingering phenomena and the early breakthrough of gas. This occurs because the gas has a relatively high mobility compared to water and thus early breakthrough of gas takes place. Lower density also allows the injected gas to migrate to the top of the reservoir and sweeps the attic oil without sweeping the bottom of the reservoir. Tertiary recovery using IWAG flooding was carried out after immiscible CO2 flooding. From the graph, an oil density of 0.72 g/cc gives the highest increment of oil recovery which is 9% as compared to other ratios.

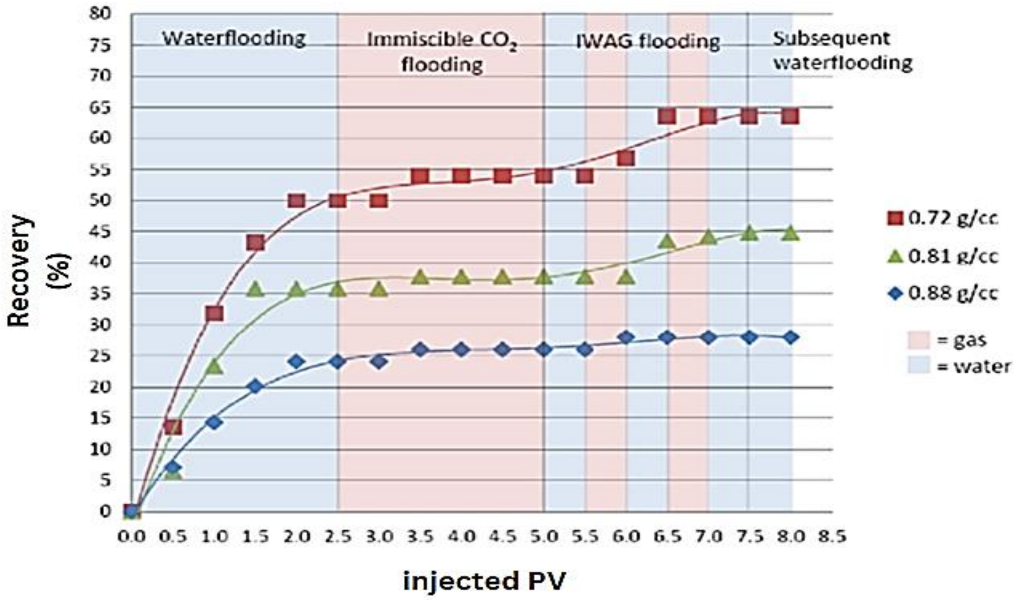


Figure II.5: Incremental RF % at Different Oil Densities (Anuar, N., and al (2017)).

- **Figure II.6:** shows that the percentage of oil recovery for tertiary recovery using WAG is inversely proportional to the oil density, with higher oil density resulting in lower oil recovery. The WAG process is different from the other methods because it is involving two important density parameters, which are the density ratio of gas to oil and water to gas. Both of these parameters will affect the performance of the WAG process. During the flooding process, gravity segregation of the fluids occurred when the gravity force due to the density difference between the fluids used is comparable with the viscous forces. Blackwell et al (1960), [6]; reported that the higher ratio of viscosity and density of water to gas would yield a higher oil recovery, viscosity fingering phenomena ,and gravity segregation due to different oil densities can be reduced. In a simulation study conducted by Stone (1982), [7]; the alteration of viscosity and density ratio can influence the effect of gravity segregation as much as 400%. Rapport (1953), [8]; reported that for each different viscosity, the density ratio will affect the efficiency of water flooding and will produce different percentages of recoveries. Thus, the properties of the fluid to be used in the experiment should be given scrutiny. By conducting this experiment with parameters of different oil densities, many factors of displacement efficiencies can be discussed. The microscopic displacement efficiency by gas is affected by IFT and capillary pressure. Meanwhile, the most important factor that affects the macroscopic displacement efficiency by water is the mobility of the displacing fluids compared with the mobility of the displaced fluids.

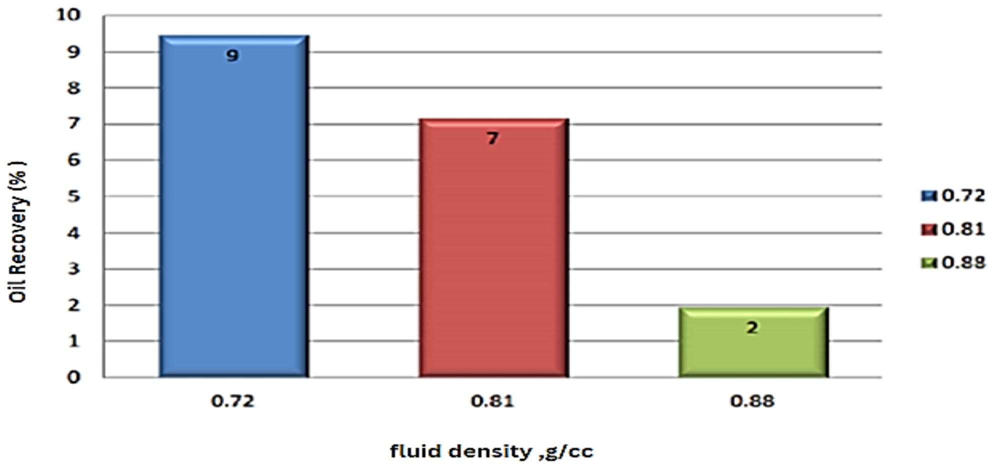


Figure II.6: Incremental RF% at Different Oil Densities (Anuar, N., and al (2017)).

Oil density (g/cc)	RF (%) Recovery percentage			Total RF (%)
	Water flooding	Immiscible CO2 flooding	IWAG	
0.72	50	4	9	64
0.81	36	2	7	45
0.88	24	2	2	28

Chart II. 3: Total Oil Recovery at Different Oil Densities (Anuar, N., and al (2017)).

- ❖ The IWAG injection experiments that studied the effect of oil recovery have been successfully completed. Through this EOR study, the following conclusion can be made:
- ✓ The density of 0.72 g/cc was optimal since the tertiary oil recovery using IWAG was 9%, and a total 64% of RF.
- ✓ The lower oil density will have higher mobility and flow with low resistance whereas higher oil density will have lower mobility and flows with a high resistance

2.2. Type of gas:

The injection of CO_2 gas at the reservoir temperature and pressure conditions is close to supercritical behavior and thus helps to increase the oil recovery during the WAG injection process.

- To improve this result, we have a study for brownfields in India:

  Details of this study:

The aim of the current work is to evaluate the performance of the different gas-injection methodologies for a given brownfield in India. It includes comparative studies on different WAG injection methods and to verify their effects on the production enhancement from the given field. Core flooding experiments are performed at close to the reservoir conditions of the pressure and temperature to identify: the recovery efficiency for different methods using different gases like hydrocarbon gas and CO_2 gas at reservoir condition. WAG processes, which have been studied and discussed in this work (on the basis of WAG cycles), are:

- Single cycle WAG using HC gas.
- Five cycles WAG using HC gas.
- Tapered WAG (with increasing and decreasing WAG ratio) using HC gas.
- Five cycles WAG using CO_2 gas.
- **Effect of injecting gas type:**

The results for five- cycle WAG using HC gas and CO_2 gas are shown in **Figures II.1 and 2,** respectively, and tabulated in **chart II.4**. The results show that CO_2 injection in five cycles WAG gives a recovery of about 97.86% of HCPV, which is very high compared to the recovery of five-cycle injection of hydrocarbon gas (about 71.3% of HCPV). This is because compared to the hydrocarbon gas CO_2 gas is having better miscibility with the crude oil at the reservoir condition which helps in increasing the solution GOR of the oil and also helps in reducing the viscosity of the oil. This probably results in the solution gas-driven production and increasing the relative permeability of the oil phase. The reservoir condition of pressure and temperature of 230 kg/cm2 and 120°C shows that the CO_2 gas may be at a near supercritical state at the reservoir condition resulting in better miscibility with the reservoir fluid.

WAG injection pattern	*Type of injection gas*	*Amount of Water injected pre-WAG process (PV)*	*Chasing water injected after WAG process (PV)*	*Total PV injected including for WAG process*	*Recovery (%HCPV)*			*Incremental recovery during chase water*	*Residual oil saturation (%HCPV)*
					Recovery with water flooding	*Incremental recovery over water flood*	*Total recovery*		
Single cycle WAG	HC gas	1.246	0.25	2.378	51.57	12.75	64.32	0	30
Five cycle WAG	HC gas	1.028	0.5	2.478	52.05	19.30	71.30	2.1	30.06
Tapered WAG (increasing WAG ratio)	HC gas	1.255	0.35	3.127	48.44	23.92	72.36	0	29.9
Tapered WAG (decreasing WAG ratio)	HC gas	1.232	0.33	3.063	51.33	16.91	72.48	4.23	16
Five cycle WAG	CO_2 gas	1.452	0.28	2.723	57.67	40.2	97.86	0	29

Chart II.4: The result of study (Ghorashi, S. S., & Akbari, K. (2017)).

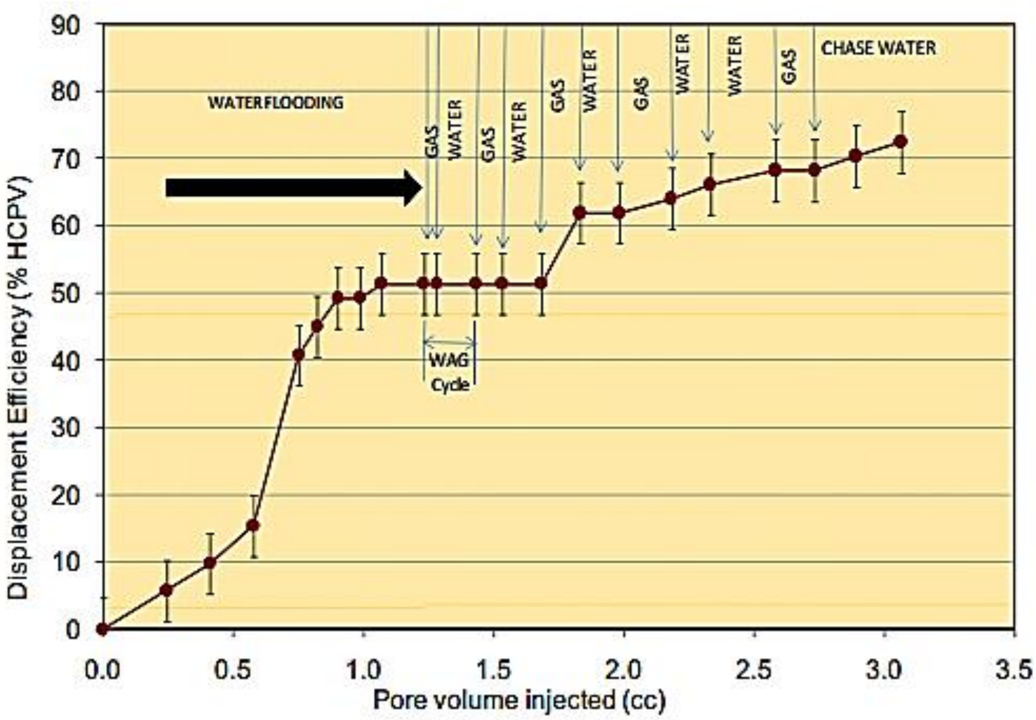


Figure II.7: Displacement efficiency vs. PV injected for five-cycle WAG injection using HC gas as injectant (Ghorashi, S. S., & Akbari, K. (2017)).

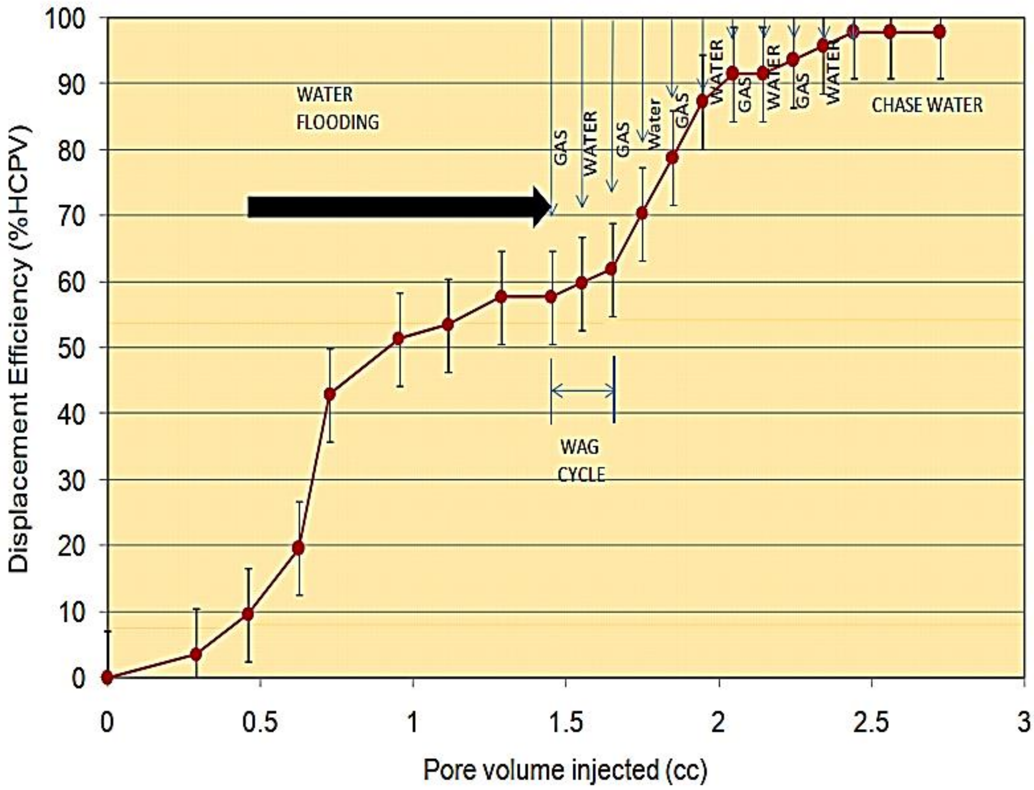


Figure II.8: Displacement efficiency vs. PV injected for five- cycle WAG injection using CO2 gas as injectant (Ghorashi, S. S., & Akbari, K. (2017)).

This second study by Ghorashi, S. S., & Akbari, K. (2017) investigates the effect of the variation of gas type on WAG performance, the simulation studies are run on a synthetic model with real PVT data of the reservoir fluid in order to perform a qualitative study of the parameters which are crucial for a WAG process design by using a commercial reservoir simulator ECLIPSE 300. Firstly, a synthetic model was simulated, and then reservoir fluid was simulated by using the real PVT data.

Gas variation effect on oil recovery during WAG Process.

In this case, water and gas were injected at a rate of 5000 STB/day and 3000 Mscf/day respectively. In WAG simulation, alternatively, the injected pressure is set at 3050 psia, which is equal to the average reservoir pressure; the total amount of one pore volume was also injected. The results are listed **in Chart II.5**. Water wet rock has a higher incremental recovery compared oil-wet wet rock due to the WAG injection process. In oil-wet rocks, water cannot produce the oil which is wetted the walls of the rock, but in water-wet rocks, the wetting phase is water, thereby pushing non-wetting oil through the production well so easier. Since the initial oil saturation for water-wet rock is different from oil-wet rock, for the correct comparison of the recovery for both rock types, the incremental recovery, which is equal to the difference between the recoveries due to WAG injection and the recovery obtained by natural depletion at the same time, was used.

Since the minimum miscibility pressure (MMP) for carbon dioxide is less than other gases, so this gas can make miscibility at a low injected pressure, whereas other gas cannot do the same. Thus, by using this gas at a low injected pressure, high oil recovery can be obtained. In this part of the study, first contact miscibility pressure (FCMP) and MMP for four different possible injecting gases were simulated by PVTI and ECLIPSE300 software (© 2009) Schlumberger respectively. It is well worth mentioning that for obtaining more accurate MMP results, the dynamic slim tube simulator was chosen. **In chart II.6**, the FCMP and MMP results for CO 2, solvent (40% C2 and 60% C1), N 2, and C1 are presented.[10]

Component	CO_2	Solvent (40% C_2 and 60% C_1)	N_2	C_1
First Contact Miscibility Pressure (psia) Simulated by PVTI software	3400	3980	14600	6400
Minimum Miscibility Pressure (psia) Simulated by dynamic Slim tube	3000	3970	13200	5500

Chart II.6: the amount of MMP and FCMP for different gases (Ghorashi, S. S., & Akbari, K. (2017)

Component	CO_2	Solvent (40%C_2 and 60% C_1)	N_2	C_1
Incremental Recovery for Water Wet rock	37.45	37	33.07	22.1
Incremental Recovery for Oil Wet rock	29.53	26.40	22.91	16.94

Chart II.5: Gas variation effect on oil recovery (Ghorashi, S. S., & Akbari, K. (2017

II.3. Fluid-rock proprieties

3.1. Relative permeability:

Relative permeability (kr) is a property used to describe flow in a multi-phase system. The property is a fluid-rock property and is defined as the ratio of the effective permeability of a particular fluid at a particular saturation to a base permeability of the porous medium, as given in equation (II. 3). The base permeability is usually referred to the absolute permeability of the porous medium.

$$kr = \frac{ke}{k} \qquad \text{(II.3)}$$

Relative permeability is dimensionless and has values between 0 and 1. If a single fluid is present in a rock, the effective permeability will be equal to the absolute permeability; hence the relative permeability will be equal to one. If the relative permeability of a fluid is zero, the fluid will be immobile.

• Relative permeability model:

• Stone 1(1970)

Stone 1 uses two set of two-phase data to predict the relative permeability of the intermediate wet phase in three-phase system. It provides interpolated data for three phase flow that are consistent and continuous functions of phase saturation (Shahverdi 2012). The original Stone's first model was modified by Aziz and Settari in 1979 for end-point relative permeability as below:

$$\mathbf{Kro} = \frac{\mathbf{so \times krow \times krog}}{\mathbf{krocw(1-sw)(1-sg)}} \qquad \text{(II.4).}$$

S_o, S_g and S w are calculated as below when $S_o > S_{om}$ and $S_w > S_{wc}$

$$So = \frac{So-Som}{1-Swc-Som} \qquad \text{(II.5).}$$

$$Sw = \frac{Sw-Swc}{1-Swc-Som} \qquad \text{(II.6).}$$

$$Sg = \frac{Sg}{1-Swc-Som} \qquad \text{(II.7).}$$

• **Stone 2 (1973) Modified**

Stone 2 (1973) on the other hand, integrated gas and water relative permeability in the calculation of three phases of the oil in mixed wet in order to get a better agreement with experiment data (Shahverdi 2012).

$$\mathrm{Kro} = \mathrm{Krocw}((\frac{\mathrm{Krw}}{\mathrm{Krocw}} + \mathrm{Krw}\left(\frac{\mathrm{Krg}}{\mathrm{Krocw}} + \mathrm{Krg}\right) - \mathrm{Krw} - \mathrm{Krg}] \qquad \text{(II.8).}$$

Krw and Krg are read from two-phase oil/water and oil/gas system relative permeabilities.

• **Baker (1988**)

Baker proposed a simple three-phase relative permeability oil, water and gas based on saturation-weighted interpolation between two-phase relative permeability data in which three phase of each phase is assumed to be function of two saturations (Shahverdi 2012; Raz 2017; Lin et al. 2014).

$$\mathbf{Kgo} = \frac{\mathbf{Sg\ Krog + (Sw - Swc)Krow}}{\mathbf{Sg + Sw - Swc}} \qquad \text{(II.9)}$$

• **Two-phase hysteresis model:**

• **Land trapping model**

Land proposed a relationship for calculating relative permeability for two- and three-phase flow for non-wetting phase in the decreasing saturation direction. This relationship honored the trapping coefficient of the non-wetting phase as the saturation starts to deplete (imbibition) and was dependent on the saturation maximum achieved during increasing saturation direction (drainage) (Tasleem 2010; Larsen and Skauge 1995).

$$\mathbf{Sgi} = \frac{\mathbf{Sgi}}{\mathbf{1 + CSgi}} \qquad \text{(II.10)}$$

Land coefficient is computed as bellow:

$$\mathbf{C} = \frac{\mathbf{1}}{\mathbf{Sgi.max}} - \frac{\mathbf{1}}{\mathbf{Sgi.max}} \qquad \text{(II.11)}$$

• **Killough (1976) and Carlson (1981)**

Killough and Carlson further developed the land saturation history dependent model by including the hysteresis effects in non-wetting phase. The Killough model hysteresis assumption on non-wetting phase hysteresis is the same as Carlson model. The only difference between these two models is that the trapped non-wetting phase saturation would be predicted using Land's model along with different formulation for scanning curve. In Carlson model, the scanning curve is assumed to be parallel to the imbibition curve. It obtained by shifting the bounding imbibition curve horizontally until it intersects the drainage curve (Spiteri and Juanes 2006).

Carlson trapped gas saturation:

$$\mathbf{Sgi} = \mathbf{Sgi.max} - \Delta\mathbf{Sgi} \qquad \text{(II.12)}$$

Killough non-wetting phase relative permeability along the scanning curve is computed as:

$$\mathbf{Kig\,.\,imb} = \frac{\mathbf{Krg(o).imb\ (Sg.norm)Krg(o).dr\ (Sg.hy)}}{\mathbf{Krg(o).dr\ (Sg.max.)}}$$

Were,

$$\mathbf{Sgi.max} + \frac{\mathbf{(Sg-Sgi)(Sg.max-Sgi.max.)}}{\mathbf{Sg.hy-Sgi}} \qquad \text{(II.13)}$$

• **Three-phase hysteresis model**

• **Larsen and Skauge (1998)**

Larsen and Skauge model is use to simulate the WAG hysteresis in combination with the standard two-phase hysteresis model (Spiteri and Juanes 2006). Non-wetting relative permeability on the drainage to imbibition scanning curve and vice versa:[11]

$$\mathbf{Kimb.rg(Sg)} = \mathbf{Kdr.rg(Sgf)} \qquad \text{(II.14)}$$

where free gas saturation using Land's equation:

$$\mathbf{Sgf} = \mathbf{Sgc} + \mathbf{1/2((Sg - Sgt)} + \sqrt{\mathbf{Sg - Sgt}}\mathbf{\hat{}2} + \frac{\mathbf{4}}{\mathbf{C(Sg-Sgt)}}]$$

and non-wetting phase using land trapping model:

$$\mathbf{Sgt} = \mathbf{Sgc} + \frac{\mathbf{Sg,hy - Sgc}}{\mathbf{1 + C(Sg,hy - Sgc)}}$$

Secondary drainage relative permeability curve:

$$\mathbf{Kdr.rg(Sg, Sstart.g, Sstart.w) = Kimb.rg(Sstart.g) + (Kdr.rg(o)(Sg) - Kdr.rg(o)(Sstart.g))(\frac{Swc}{Sstart.w})} \quad \text{(II.15)}$$

The effect of relative permeability on oil recovery:

- **Description of model:**

(Elizabeth J. Spiteri et. Al) consider a quarter of a five-spot pattern in a homogeneous, horizontal reservoir. The porosity is 0.2 and the horizontal permeability is 200 md, which coincides with the absolute permeability of the core from which the relative permeability values were measured. The domain is discretized into $25 \times 25 \times 1$grid blocks, each of dimension $40 \times 40 \times 100$ft. The total pore volume is $2 \times 10^7 ft^3$.they used relative permeability data from the Oak experiments, Capillary pressure was ignored in this study. They employed very simple PVT data, representative of immiscible fluids (dead oil and dry gas). For simplicity, we took the water density and viscosity as 62.4 lb/ft^3 and 1 cP, respectively. The oil density and viscosity are 43.7 lb/ft^3 and 2 cP, respectively. The formation volume factor of water and oil is taken as exactly 1 rb/stb. The PVT properties of gas are given in **Chart II.5.** Ase functions of pressure. The gas density at a reference pressure of 14.7 psia is 0.063 lb/ft^3. At average reservoir conditions (about 2000 psia), the gas formation volume factor is approximately equal to 1 rb/stb, and the gas viscosity is approximately equal to 0.02 cP. The reservoir is initially saturated with oil and connate water, and the initial reservoir pressure is 2000 psia. During the first 5 yr, one pore volume of water is injected. After water injection, most of the reservoir contains oil at residual saturation to water. Since the residual oil saturation to gas is significantly lower than the residual oil saturation to water ($S_{org}<S_{orw}$), gas is then injected to produce more oil. A WAG injection scheme is then adopted, by injecting and producing one pore volume of fluid every 5 yr., with a 1:1 WAG ratio. The injectors are controlled by voidage replacement, so the volume of fluid injected is the same as the volume produced. The producer is set to a target oil rate of 1000rb/day, with a limit in the bottom hole pressure (BHP) of 1900 psi.

The effect of the interpolation model and the hysteresis model was studied by comparing recovery efficiencies, saturation paths, gas–oil ratios (GOR), and water cut (WCT).

Pressure (psia)	Gas FVF (rb/stb)	Viscosity (cP)
14.7	192.5	0.0107
145.0	18.99	0.0109
290.1	9.242	0.0111
435.1	5.997	0.0114
580.2	4.374	0.0117
725.2	3.404	0.0121
870.2	2.759	0.0126
1015.3	2.301	0.0131
1305.3	1.699	0.0144
1740.5	1.199	0.0171
2175.6	0.928	0.0205

Chart II.7: Dry gas PVT properties (Elizabeth J. Spiteri et al ;(2005)).

- **Result:**

- In **Fig II.9**They observe the recovery efficiency predicted for different hysteresis models, when the Stone I interpolation model is used.

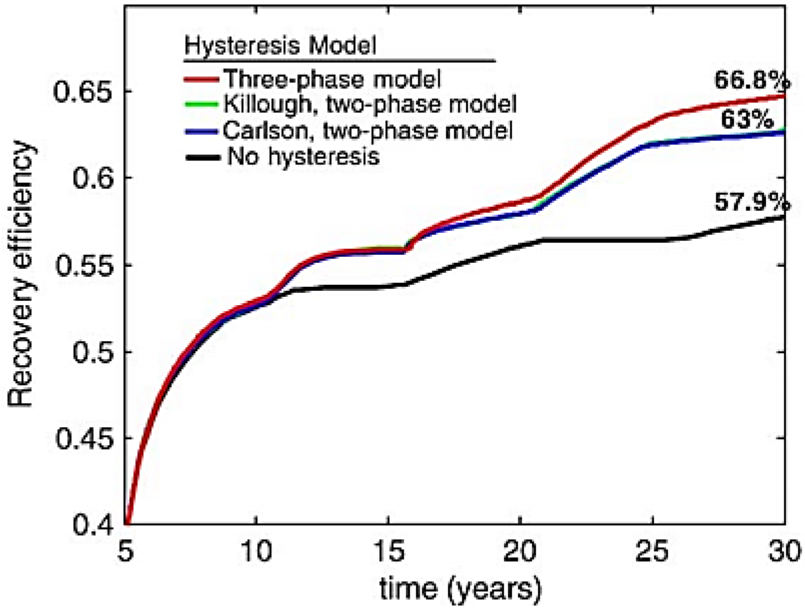


Figure II.9: Recovery efficiency predicted by each hysteresis model using the Stone I interpolation model (Elizabeth J. Spiteri et al ;(2005)).

- In **Figure II.10:** They plot the recovery efficiency obtained for different values of the Land trapping coefficient. The simulated recovery increases as the trapping coefficient decreases

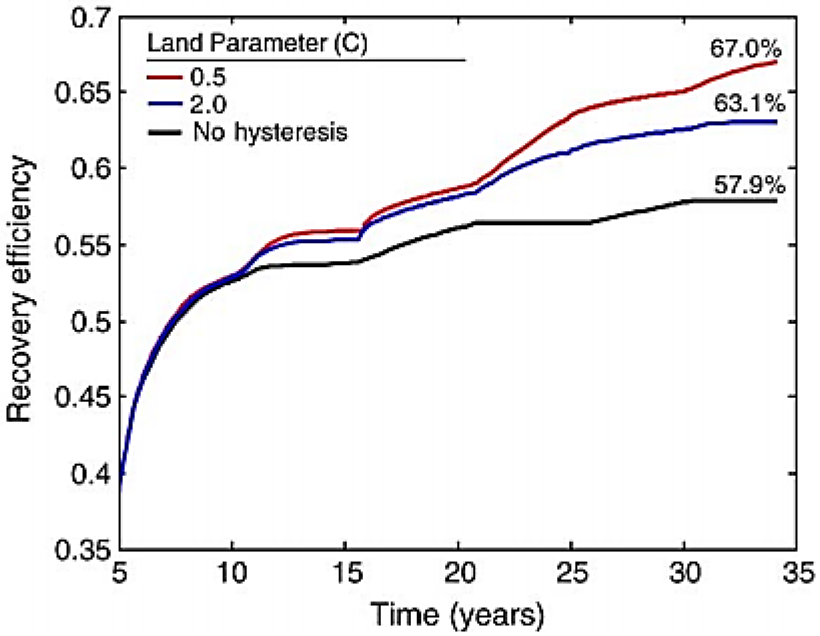


Figure II.10: Recovery efficiency for the WAG three-phase model and the Stone I interpolation model, using different Land trapping coefficients (Elizabeth J. Spiteri et al ;(2005)).

Case	Recovery scheme	Hysteresis model	Interpolation model	Land parameter (*C*)	% Recovery	% Difference from base case
1	Waterflood (base case 1)	None	None	N/A	49.0%	0.0%
2	WAG (base case 2)	None	Baker	N/A	50.8%	0.0%
3	WAG (base case 2)	None	Stone I	N/A	57.9%	0.0%
4	WAG (base case 2)	None	Stone II	N/A	55.9%	0.0%
5	WAG	Carlson	Baker	0.78	53.2%	4.7%
6	WAG	Carlson	Stone I	0.78	63.4%	9.5%
7	WAG	Carlson	Stone II	0.78	60.1%	7.5%
8	WAG	Killough	Baker	0.78	53.3%	4.9%
9	WAG	Killough	Stone I	0.78	62.8%	8.5%
10	WAG	Killough	Stone II	0.78	60.0%	7.3%
11	WAG	3-Phase WAG	Baker	0.78	53.5%	5.3%
12	WAG	3-Phase WAG	Stone I	0.78	66.8%	15.4%
13	WAG	3-Phase WAG	Stone II	0.78	59.2%	5.9%
14	WAG	3-Phase WAG	Stone I	0.5	67.0%	15.7%
15	WAG	3-Phase WAG	Stone I	1	65.4%	13.0%
16	WAG	3-Phase WAG	Stone I	2	63.1%	9.0%

Chart II.8: Summary of simulation results for the synthetic reservoir test cases

(Elizabeth J. Spiteri et al ;(2005)).

- For more improving of this result, they are using a realistic reservoir; they selected the PUNQ-S3 model, which is a well-known reservoir model originally developed as a test case for production forecasting under uncertainty. All the simulations were conducted with the Eclipse 100 black-oil reservoir simulator.

- **Model description:**

They modified the original PUNQ-S3 model by changing the injection and production scheme, and the fluid composition. They used the same PVT and relative permeability data as in the synthetic model of the previous section. Well locations are also slightly different from the original model. Our model has four injection wells and four production wells, open to the third, fourth, and fifth layers of the reservoir. The production wells operate at a fixed bottom hole pressure of 2000 psia. The injection wells are rate controlled, and inject 6290 rb/day each (25,160 rb/day total). The WAG ratio is 1:1 with a slug size of 0.1 pore volumes, which was found to be an optimum operation scheme (Cakici, 2003). They simulated three WAG cycles of 2500 days each for a total simulation time over 7500 days (21 yr).

- **Result II:**

  - The oil recovery efficiency for different interpolation models (Stone I, Stone II and Baker) is plotted in **Figure II.11. As** for the synthetic case, the Stone I model predicts the highest recovery.

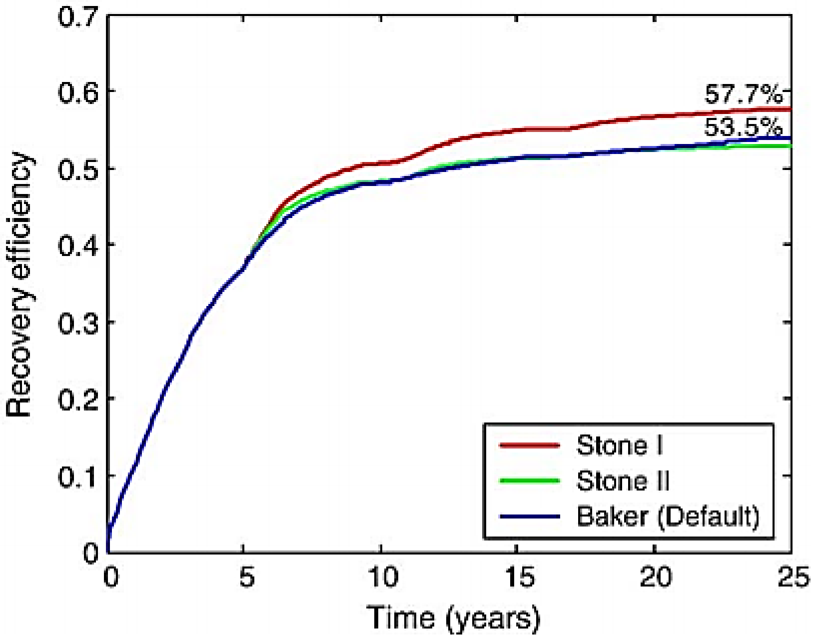


Figure II. 11: Recovery efficiency in the PUNQ-S3 reservoir model for different interpolation models, without hysteresis (Elizabeth J. Spiteri et al ;(2005)).

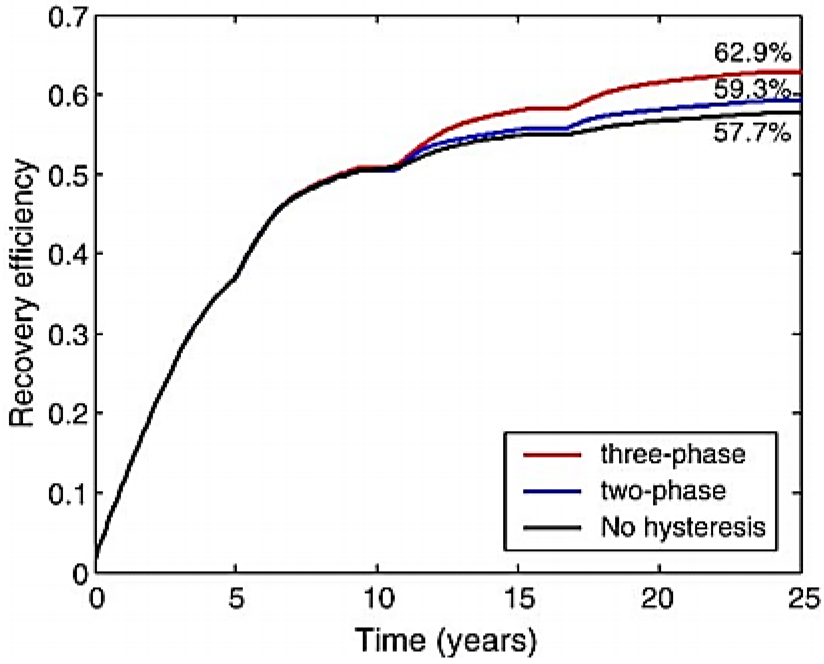


Figure II.12: Recovery efficiency in the PUNQ-S3 reservoir model for different hysteresis models, and the Stone I interpolation model (Elizabeth J. Spiteri et al ;(2005)).

- The impact of using a hysteretic relative permeability model for oil recovery prediction is shown in **Figure II.12**. Recovery efficiency obtained by using Killough's two-phase hysteresis model and the WAG three-phase hysteresis model is compared with the recovery efficiency predicted with a non-hysteretic model. Differences of up to 9.4% in ultimate recovery are obtained. Although not as dramatic as for the synthetic case, the impact of relative permeability hysteresis is still very significant.

Case	Recovery scheme	Hysteresis model	Interpolation model	Land parameter (*C*)	% Recovery	% Difference from base case
1	WAG-PUNQS3 (base case)	None	Baker	N/A	53.9%	0.0%
2	WAG-PUNQS3 (base case)	None	Stone I	N/A	57.7%	0.0%
3	WAG-PUNQS3 (base case)	None	Stone II	N/A	53.0%	0.0%
4	WAG-PUNQS3	Carlson	Stone I	N/A	59.3%	2.8%
5	WAG-PUNQS3	3P WAG model	Stone I	0.78	62.9%	9.0%

Chart II.9: Summary of simulation results for the PUNQ-S3 test case

(Elizabeth J. Spiteri et al ;(2005)).

- **FINALLY,** the results of this investigation support the view that three-phase permeability hysteresis models lead to much larger recovery predictions than non-hysteretic models, because they account for the reduced mobility due to trapping of the gas phase during water injection. Depending on the interpolation model used, the difference in recovery efficiency could be as large as 15%. The simulation of WAG injection in the PUNQ-S3 model then confirmed these findings.[12]

3.2. Oil Saturation

Saturation is defined by Tarik (2001) as that fraction or percentage of the pore volume occupied by a particular fluid (oil, gas, or water). This is given as:[12]

$$\text{fluid saturation} = \frac{\text{total volume of fluid}}{\text{pore volume}} \qquad \text{(II.16)}$$

- **Impact of oil saturation on recovery factor:**

Several WAG experiments for coreflood on sandstone cores like Skauge and Larsen (1994) study; Minssieux and Duquerroix (1994); Element et al. (2003). More details on these experiments can be found in Sohrabi et al. (2007), Fatemi et al. (2012), Fatemi and Sohrabi (2015).

- **chart II.10** summarizes different WAG experiments started with water (WAG-ID) with the residual oil saturation after cyclic injection of water and gas for different gas/oil IFT values in 65 and 1000 mD water-wet and mixed-wet Clashach sandstone cores.

Rock	Wettability	IFTg/o	S_{oi}	$S_{or}W1$	S_{or} G1	$S_{or}W2$	S_{or} G2	$S_{or}W3$	S_{or} G3
1000 md	MW	0.04	0.92	0.23	0.115	0.06	0.009	–	–
65 md	WW	0.04	0.82	0.415	0.30	0.26	0.2	0.167	0.095
65 md	MW	0.4	0.82	0.18	0.144	0.127	0.105	0.096	0.027
65 md	MW	0.15	0.82	0.271	0.265	0.247	0.234	0.224	0.214
65 md	MW	2.7	0.82	0.18	0.305	0.29	0.29	0.28	0.28

Chart II.10: Residual oil saturations during WAG-ID injection in 65 and 1000 mD Clarsach cores (Sohrabi et al. (2007)).

- **Chart II.11** presents the WAGexperiments started with gas (WAG-DI) and the residual oil saturation after cyclic injections for differentgas/oil IFT values in 65 mD mixed-wet core.

Rock	Wettability	IFTg/o	Soi	S_{or} G1	S_{or}W1	S_{or} G2	S_{or}W2	S_{or} G3	S_{or}W3	S_{or} G4	S_{or}W4
65md	MW	0.04	0.82	0.29	0.19	0.16	0.14	0.11	0.095	0.07	0.05
65md	MW	0.15	0.82	0.305	0.168	0.153	0.141	0.133	0.124	0.113	0.105
65md	MW	2.7	0.82	0.35	0.089	0.082	0.068	0.064	0.06	0.06	0.057

Chart II.11: Residual oil saturations during WAG-DI injection in 65 Md Clashach (Sohrabi et al. (2007)).

Chart II. 12 And Chart II.13 present the residual oil saturations and oil recovery, respectively, for different experiments including WAG-DI (started with gas injection) and WAG-ID (starting with water injection) injection scenarios.

Rock	Orientation	Wettability	WAG-DI (starts with Gas)				WAG-ID (starts with Water)			
			S_{oi}	S_{or} G1	S_{or}W1	S_{or}G2	S_{oi}	S_{or} W1	S_{or}G1	S_{or} W2
Berea	Horizontal	WW	0.733	0.213	0.079	0.075	0.73	0.44	0.438	0.391
Silanized, Berea*	Horizontal	?	0.725	0.236	0.158	0.156	0.699	0.147	0.141	0.089
R1(North Sea)	Horizontal	WW	0.692	0.23	0.201	0.191	0.778	0.377	0.359	0.303
R2(North Sea)	Vertical	MW	0.64	0.35	0.16	–	0.63	0.28	0.18	–
R3(North Sea)	Vertical	MW	0.775	0.093	–	–	–	–	–	–
R4(North Sea)	Vertical	WW	0.381	0.191	0.145	–	0.489	0.218	–	–

Chart II.12: Residual oil saturation for each experiment (Skauge and Larsen (1994)).

Rock	Orientation	Wettability	Secondary WAG	Tertiary WAG
Berea (B)	Horizontal	WW	89.7	46.4
Silanized Berea	Horizontal	?	78.5	87.2
R1	Horizontal	WW	72.4	61.1
R2	Vertical	MW	75	71.4
R3	Vertical	MW	88	–
R4	Vertical	WW	61.9	55.4

Chart II.13: Oil recovery (%) for different experiments (Skauge and Larsen (1994)).

- **Result:**

• **Figure II.13** shows that the oil saturation in the 65 mD mixed-wet core, at IFTg/o of 0.15 and 2.7 mNm^{-1} conditions, decreased insignificantly after the secondary water flooding. This means during any of the subsequent cycles of WAG injection (i.e., end of G1, W2, G2, W3 and G3; the red curve) the residual oil saturation decreased due to three-phase flow mechanism and hysteresis effect but the reduction is limited while in the near-miscible conditions (IFTg/o = $0.04 mNm^{-1}$) it decreased continuously even during the later stages of WAG injection. The similar continuous trend of reduction in residual oil saturation during thenear-miscible WAG injection can be seen in the experimental results of the 1000 mD core.

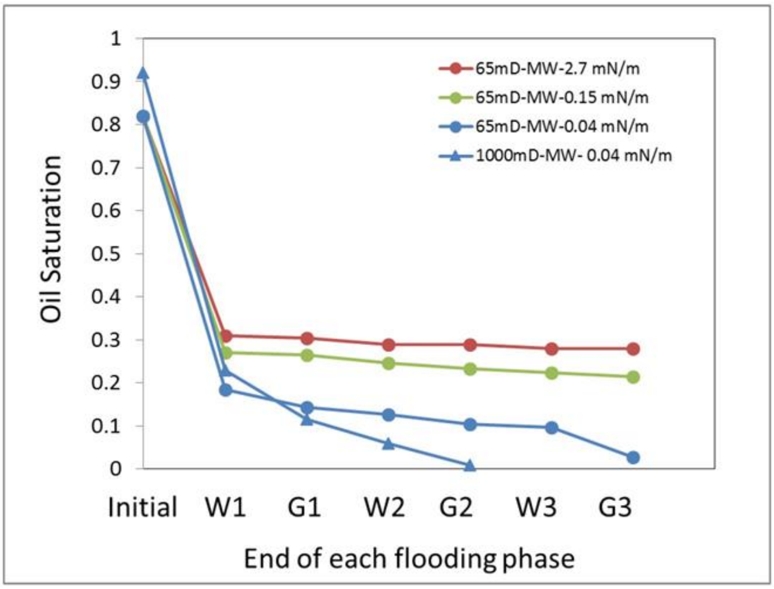


Figure II.13: Residual oil saturation at the end of each flooding phase during WAG-ID injections in 65 and 1000 mD mixed-wet (Sohrabi et al. (2007)).

• **Figure II.14** compares the reduction of oil saturation during WAG-DI injections at three different gas/oil IFT values. Unlike the WAG-ID results, WAG-DI at high gas/oil IFT value shows better performance than intermediate IFT value Similarly, the WAG-DI at near-miscible conditions, had lower performance than WAG-DI at high IFT value, but continuous reduction of residual oil during the cyclic injections at near-miscible conditions caused even a better performance at the end of forth cycle. As a result, it can be concluded that in WAG-ID and DI injections at near-miscible conditions, the residual oil continuously decreased during the injections and the recovery was higher compared with the injections at intermediate and high gas/oil IFT values.

Comparing the results of WAG-ID and WAG-DI injections in 65 mD mixed-wet core at immiscibleconditions (0.15 and 2.7 mNm^{-1}) shows that the performance of WAG injection started with gas was better than the WAG started with water. However, the near-miscible WAG-ID injection, especially in the first cycle, outperformed WAG-DI injection. Moreover, the performance of WAG in mixed-wet system was much better than water-wet system for the 65 mD core and still much better in the 1000 mD mixed-wet core (as expected).

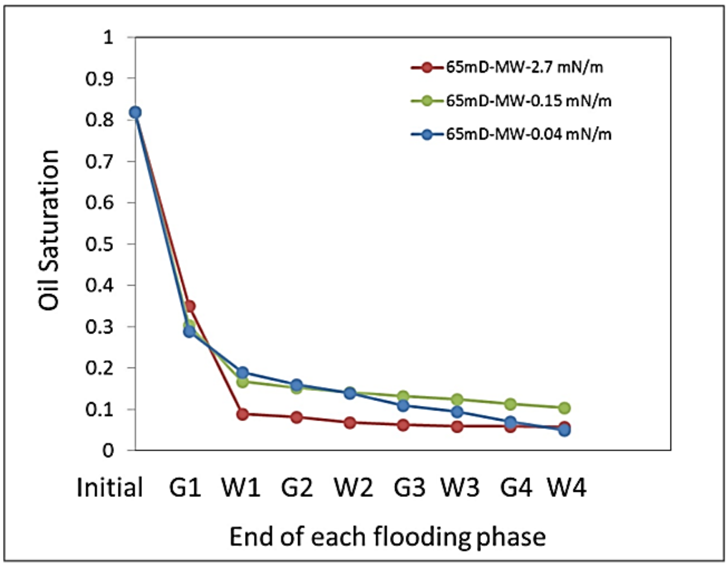


Figure II.14: Residual oil saturation at the end of each flooding phase during WAG-DI injections in 65 mD mixed-wet core (Sohrabi et al. (2007)).

- **Figure II.15** compares the changes in residual oil saturation for Berea and R1 cores during immiscible WAG-ID and DI injections. The residual oil saturations for two complete cycles of alternative gas and water injection were available only for these two cores. It is observed that for both set of cores, Berea and North Sea, when the WAG processes started with gas injection it had higher oil recovery than those tests, which started with water flooding.

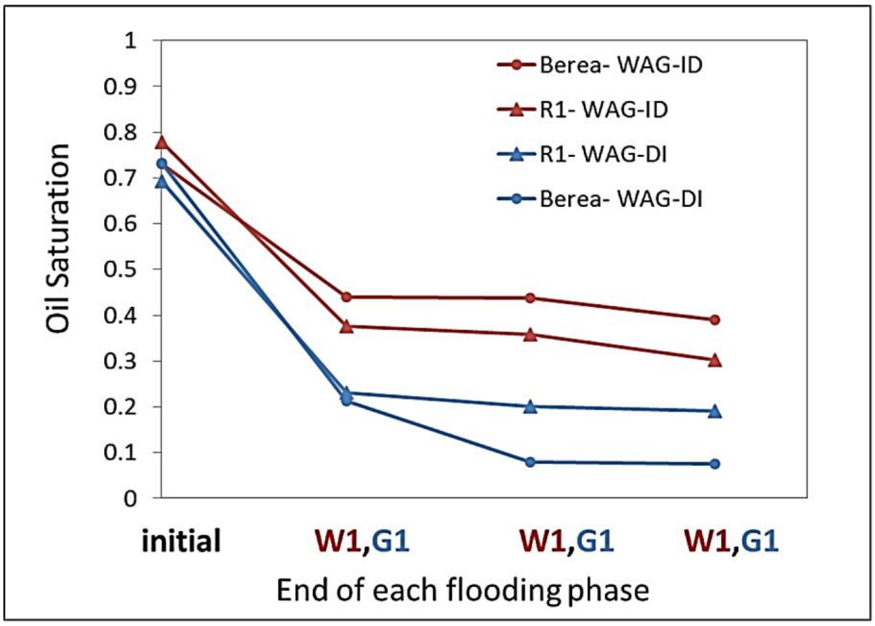


Figure II. 15: Residual oil saturation at the end of each flooding phase during WAG-DI (**Blue**) and WAG-ID (**Red**) for Berea Sandstone and R1 North Sea cores(Skauge and Larsen (1994)).

- ❖ In addition, comparing the results obtained from the North Sea reservoir cores, it could be concluded that the performance of WAG in mixed-wet system was much better than water-wet system whether it started with gas injection or water flooding. Similarly, according to our experimental results on 65-mD Clashach sandstone core, also the performance of WAG in mixed-wet system was better than that of the water-wet system.

Furthermore, in these immiscible WAG processes, the largest portion of recovery (decrease in oil saturation) occurred in the first cycle of injections and the decrease in residual oil saturation was not significant in the later injection periods.[13]

II.4. Discussion:

Laboratory research and detailed reservoir simulation plays a very important role in the development and implementation of WAG injection projects. **In this chapter** ;we have touched on various data ;including : Rock proprieties(**permeability** which determines the ability of fluids to flow through the reservoir rock, influencing the overall efficiency of the injection process); Fluid-rock proprieties(**saturation** refers to the proportion of fluids present in the pore space of the rock, affecting the displacement and sweep efficiency ;**Relative permeability** describes the relative ability of different fluids to flow through the reservoir, impacting the displacement and recovery of oil);Fluid proprieties(**density** has an influence for the mobility of oil within the reservoir ; **type of gas** this can have varying miscibility, and viscosity effects on the oil, influencing the displacement efficiency); and Operational conditions(WAG ratio; WAG cycle time ;WAG slug size; WAG cycle length; Selecting of the starting phase; WAG cycle number)these parameters we will investigate **in the third chapter** and they can be defined as follows:

- ✓ The WAG ratio refers to the ratio of water to gas injected during the alternating phases.
- ✓ WAG cycle time refers to the duration of each water and gas injection cycle
- ✓ Slug size refers to the volume of fluids injected during each phase of the WAG process. Controlling the slug size is critical in achieving desired displacement efficiency. An appropriate slug size helps in minimizing viscous fingering effects, leading to improved oil recovery.
- ✓ The number of cycles determines how many times the alternating water and gas injections are performed.
- ✓ WAG cycle length refers to the duration of each injection phase within a cycle. Optimizing the cycle length helps in achieving an effective balance between the reservoir's fluid contact time and the displacement rate.
- ✓ The composition of the first phase injected, typically water, can significantly influence the success of the WAG process. Injecting water initially helps in mobilizing and displacing oil from the reservoir.

CHAPTER III:

Impact of field conditions on WAG performance.

❖ In this chapter, we have to study the impact of different **WAG** parameters on recovery factor. These parameters refer to WAG slug size, WAG ratio, WAG cycles time, WAG cycle length, WAG cycle number and selecting of the starting phase.

Figure III.1: Different **WAG** parameters (Hadjer.K; Aya.K;(2023)).

III.1. The Impact of WAG ratio on oil recovery

- **Methodology:**

  - Carbon dioxide Prophet Model is selected to be used in this project. CO_2-Prophet was developed by Texaco Exploration and Production Technology Department (EPTD). CO_2 Prophet was developed as an alternative to the U.S. Department of Energy's CO_2 miscible flood predictive model, CO_2PM. Both models are screening tools which fall between crude empirical correlations and sophisticated numerical simulators. CO_2 Prophet has more capabilities and fewer limitations than CO_2PM. CO_2-Prophet was designed to identify how key variables influence CO_2 project performance and economics prior to performing detailed numerical simulation. The model manual stated that CO_2-Prophet performs two principal operations. It first generates streamlines for fluid flow between injection and production wells and then does displacement and recovery calculations along the stream tubes. The streamlines form the flow boundaries for the stream tubes. In the model for the displacement calculations a finite difference routine was employed. The grid orientation effects were eliminated in the used model. Streamlines and stream tubes were used to handle the effect of area sweep efficiency. The miscible CO_2 process was simulated by using a mixing parameter approach similar to the approach proposed by Todd and Long staff.

In these models, the mixing and viscous fingering are simulated by adjusting solvent and oil viscosities.

The reservoir model is a standard quarter 5-spot pattern with an injector and a producer were used with all sided of the sector bounded by no flow boundaries. Other patters were used to optimize the CO_2-WAG flooding patterns. Table 1 presents the model input data for all studied cases. The effect of WAG ratio, wettability, flooding rate, pattern type, project timing, and system wettability were investigated in this project. The effect of CO_2-WAG on the recovery efficiency of an oil wet system was initially investigated. Five different CO_2-WAGs of 1:1, 1:2, 2:1, 1:3, and 3:1 was conducted in additional to continue CO_2 flooding. At the end of WAG flood continues water flooding initiated, and the process is continued to residual oil saturation. The effect of system wettability (oil wet, and water wet) on the CO2-WAG flooding was also investigated. Five flow rates (500, 1000, 1500, and 2000 bbl/day) were employed to assess the effect of injection rate on the performance of CO_2-WAG process. Three different injection patterns (5, 7, and 9) in addition to line drive for both oil-wet and water set systems were used to optimize the injection pattern of the CO_2-WAG flooding. The effect of initial fluid saturations (project timing) on the process efficiency was investigated. Four runs were conducted using initial water saturation of 0.2, 0.45, 0.6, and 0.75. Finally, the permeability variation of the system was varied between 0.1 for a homogenous system to 0.85 representing a heterogeneous system.

WAG ratio Optimization:

- The effect of WAG ratios on the performance of carbon dioxide flood using an oil wet system was investigated by conducting six runs as follows: WAG 1:1, 2:1, 1:2, 3:1, 1:3 and continues carbon dioxide flooding. A fixed pore volume of carbon dioxide injection of 0.2 hydrocarbon pore volume injected (HCPV) was used for all runs. Oil recovery versus pore volume injected for all studies cases is presented in **Figure III.2**

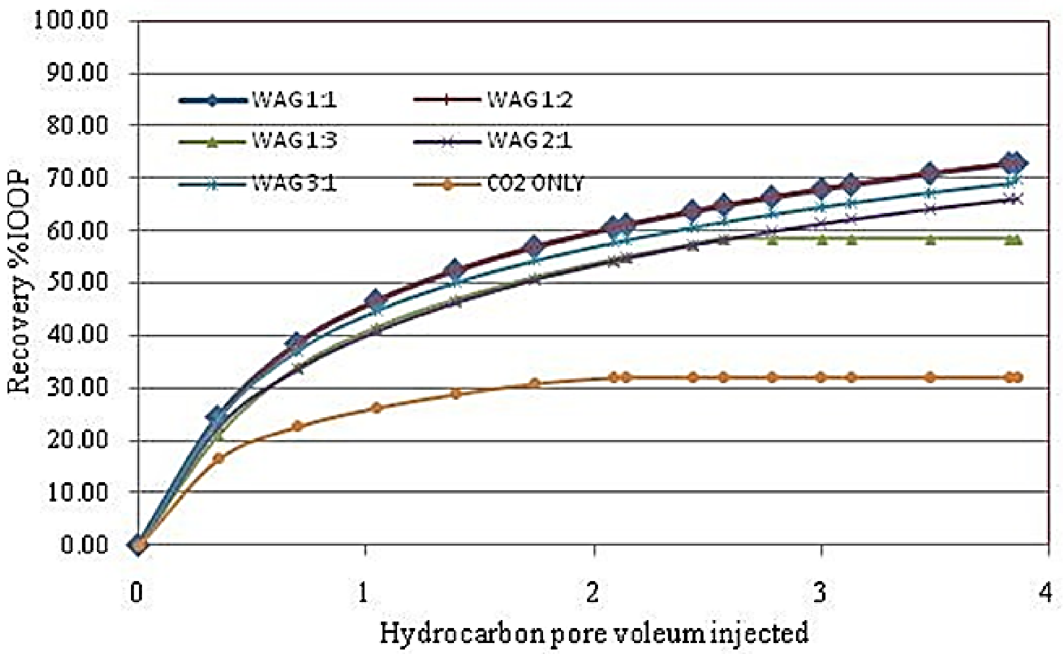


Figure III.2: Oil recovery versus CO_2 pore volume injected for different WAG ratio.
(Zekri, A. et al (2011, July).

Results of these runs indicted that higher oil recovery could obtained by using WAG's 1:1 or 1:2 compared to other WAG's and the WAG ratio has a significant effect on the performance of carbon dioxide flooding process. Results indicated that there is no significant difference in the overall recovery between WAGs of 1:1 and 2:1 for the oil-wet system which in line with the conclusion previously reported by Zekri and Nate, 1992. Continues carbon dioxide flooding has showed poor performance (oil recovery of 32% RF). The poor performance of continues carbon dioxide flooding can be attributed to the low volumetric sweep efficiency as a result of high mobility ratio of the studied system.

- In general, increasing the WAG ratio enhances the performance of the WAG process by improving the volumetric sweep efficiency. WAG ratios of 3:1, 2:1, and 1:2 have yielded an oil recovery of 70, 66.04, and 58.48% of Recovery factor respectively, as shown in **Figure III.3.**

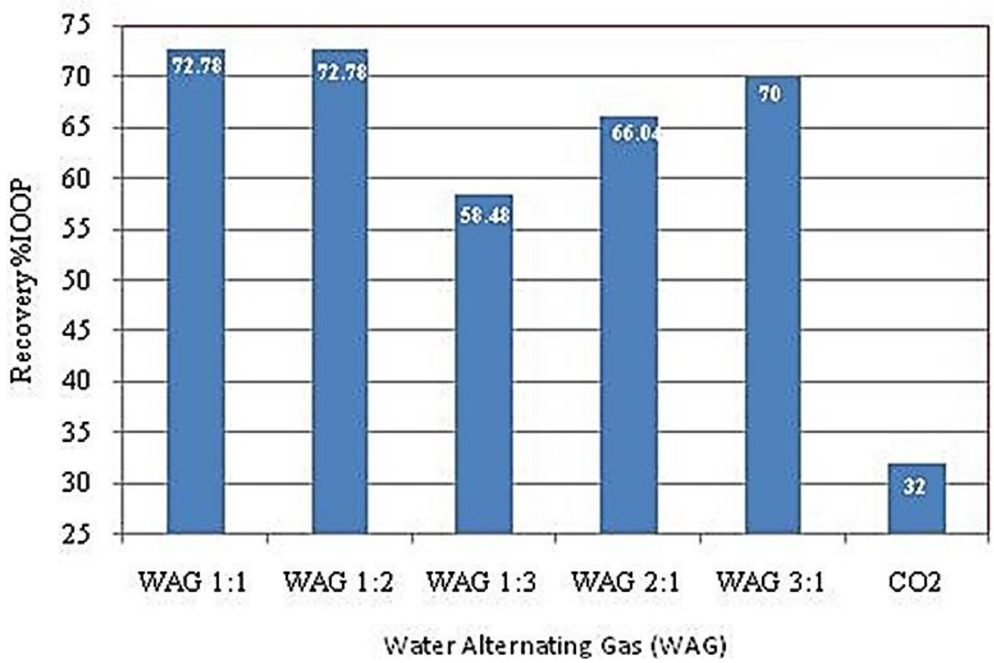


Figure III.3: Oil recovery versus WAG ratios. (Zekri, A. et al (2011, July).

- ❖ Based on the results of this study they are conclude:

-Increasing the WAG ratio enhances the performance of the WAG process by improving the volumetric sweep efficiency.[14]

III.2. The Impact of WAG cycle time

- **Methodology:**

Mohammed-Singh & Singhal (2005) studied immiscible CO_2 projects in the Forest Reserve and Oropouche regions and characterized the geology found in these areas. Typical data values found in both fields as published by (Mohammed-Singh & Singhal) include:

- Medium-gravity oil.
- **µ:** 6 – 46 cp.
- **K:** up to 350 md.
- Reservoir thickness: 35 – 395 ft.
- Shallow depths: 2,160 – 4,200 ft.
- Sloping beds: 0° ⁻30° dip.

For this paper, the following reservoir, fluid parameters and geological assumptions were used for the JLG field **(see chart III.**1) based on the research of analogues from these areas.

Reservoir and Fluid Properties	Assumptions
Area, A=200 acres	• No fault present
Temperature, T=130°F	
Top of Structure=3500 ft	• Normally pressured – 0.465 psi/ft
Thickness, h=160 ft	
Porosity, Φ=30%	
Permeability, k (4 layers) =170 – 310 mD	• Limited reservoir fluid impurities
Pressure, P=1627.5 psia	• No sand production
API Gravity=25°	• Negligible skin factor
RF=29,750 MSTB	

Chart III. 1: Field, JLG parameters and assumptions (Hernandez, J.et al (2016, June)).

- **Result:**

In this paper four WAG cycle time were chosen: three months, one year, two years and three years, to determine which would be the best for the field. These were chosen based on the intensive literature review done and also outside the normally ranged scenarios to allow a broader comparison (**Nangacovie, 2012; Touray, 2013; Wu et. al., 2004).** The rates were varied but the WAG ratio and HCPV was kept constant at 2:1 and 100% HCPV respectively as shown in figure III. 4.

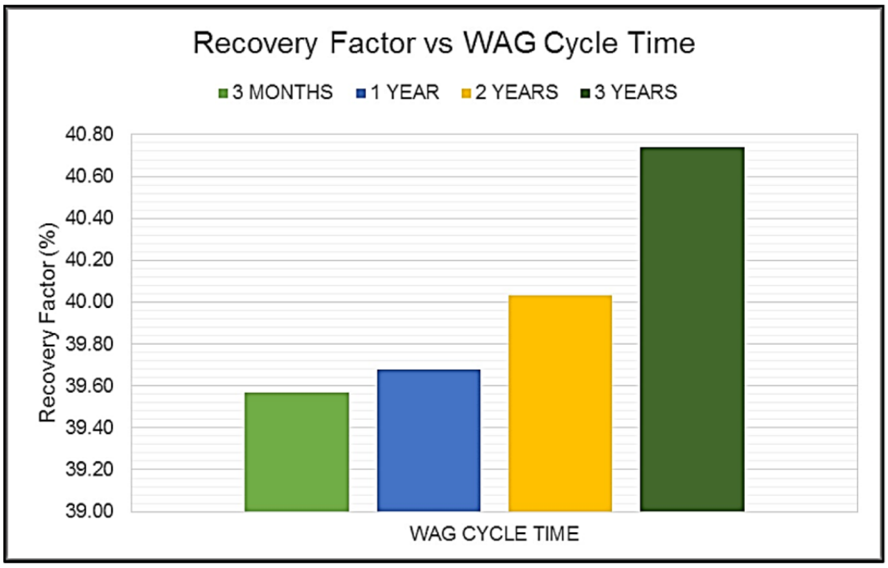


Figure III.4: Effects of WAG cycle time (Hernandez, J.et al (2016, June)).

- **Figure III.4** Clearly shows that the variation in the injection rate and WAG cycle time influenced the cumulative production of oil, but with little impact. It is therefore concluded that the injection rates of theCO_2 were totally dependent on time. The 3 years WAG cycle time gave the highest recovery factor. Hence from this analysis, it was concluded that it is rather wasteful to inject water and gas for 3 months, 1 year or 2 years cycle because the incremental increase of residual oil is independent of time.[15]

III.3. The Impact of WAG Slug size

- **Methodology:**

  - Rock Core Sample

A two-foot long 2-inch diameter homogenous Clashach sandstone core was selected for the experiments presented in this paper. The initial wettability of this outcrop was water-wet. The core was then aged usinga crude oil, and turned into a mixed-wet system. Details of the aging and wettability alteration process and some mixed-wetness indications were given in our previous publications (Fatemi and Sohrabi, 2013). Thephysical properties of the core sample were measured. The absolute brine permeability and porosity were equal to 65 mD and 18% respectively. The measured volumetric porosity was also checked by the X-ray and it was in the good agreement with average porosity profile throughout the core length. The porosity profile also illustrated that there were no major heterogeneities within the core length. All the experimentswere performed in a horizontally-oriented core with no gravity effect (by rotating the core).

  - Experimental Procedure

Five core-flood experiments are reported in this paper **Chart III.2**. The core was prepared for each experiment as described above. The core was then fully saturated with brine. Subsequently, a permeability measurement test carried out to measure the core's permeability to brine. The immobile water saturation (S_{wim}) wasthen established, using a series of mineral oils and normal alkanes. At the end of this stage the core was fully saturated with pre-equilibrated oil (82.0 %) and 18.0 % of immobile water saturation. It is worth mentioning that the relative permeability to oil (k_{ro} at S_{wim}=18.0 %) were regularly measured at the startof all experiments.

Exp. No	Experiment	Description	Slug Number and Size
1	SS-GAW	Short Slug Gas Alternating Water Injection	6 Gas Slugs (0.15 PV) 6 Water Slugs (0.15 PV) 1 Gas Slug (~2 PV) 1 Water Slug (~2 PV)
2	SS-WAG	Short Slug Water Alternating Gas Injection	6 Water Slugs (0.15 PV) 6 Gas Slugs (0.15 PV) 1 Water Slug (~2 PV) 1 Gas Slug (~2 PV)
3	SWAG	Simultaneous Water and Gas Injection	Water/Gas Co-Injection
4	LS-GAW	Large Slug Gas Alternating Water Injection	4 Gas Slugs (~2 PV) 4 Water Slugs (~2 PV)
5*	LS-WAG	Large Slug Water Alternating Gas Injection	4 Water Cycles (~2 PV) 4 Gas Cycles (~2 PV)

Chart III.2: List of five core-flood experiments performed for this study (Alkhazmi, B. et al (2017, October)).

- In the SS-GAW (short slug gas alternating water) experiment, the injection started with a gas slug size of 0.15 PV, followed by a water slug of the same size. The experiments continued with another six cycles of gas and water on 65mD mixed-wet core. The experiment was then completed by extended water and gas slugs. The same strategy was followed in conducting the SS-WAG injection experiment; however, the test started with the 0.15 PV water cycle and the extended cycle was gas. Thus, the objective of these experiments was to investigate the effect of the order of injection on the performance of the WAG process. Adding the extended cycle into both injection scenarios, SS-GAW and SS-WAG, was to investigate whether the large slugs would change the saturation distribution across the core and subsequently affect the oil recovery or not. It is worth mentioning that two- and three-phase mixings were carried out after each injected cycle in order to validate the accuracy of the experimental results obtained from each injection period. The details of the LS-GAW (large slug gas alternating water, Experiment 3) and LS-WAG (large slug water alternating gas, Experiment 4) were reported in our previous publication (Fatemi and Sohrabi, 2015).

❖ Result

- To study the effect of water and gas slug sizes on WAG injection performance in terms of oil recovery, the recovered oils (RF %) for the core-flood experiments commenced with the same injection order, for instance, SS-GAW versus LS-GAW and SS-WAG versus LS-WAG, are plotted against the injected PV of fluids.

- In addition, **Figure III.5** Compares the performance of oil recoveries (RF %) for all core flood experiments, including Gas Flood (GF), Water Flood (WF), LS-GAW, LS-WAG, SWAG, SS-GAW and SS-WAG, which were carried out with different injection strategies and at immiscible conditions.

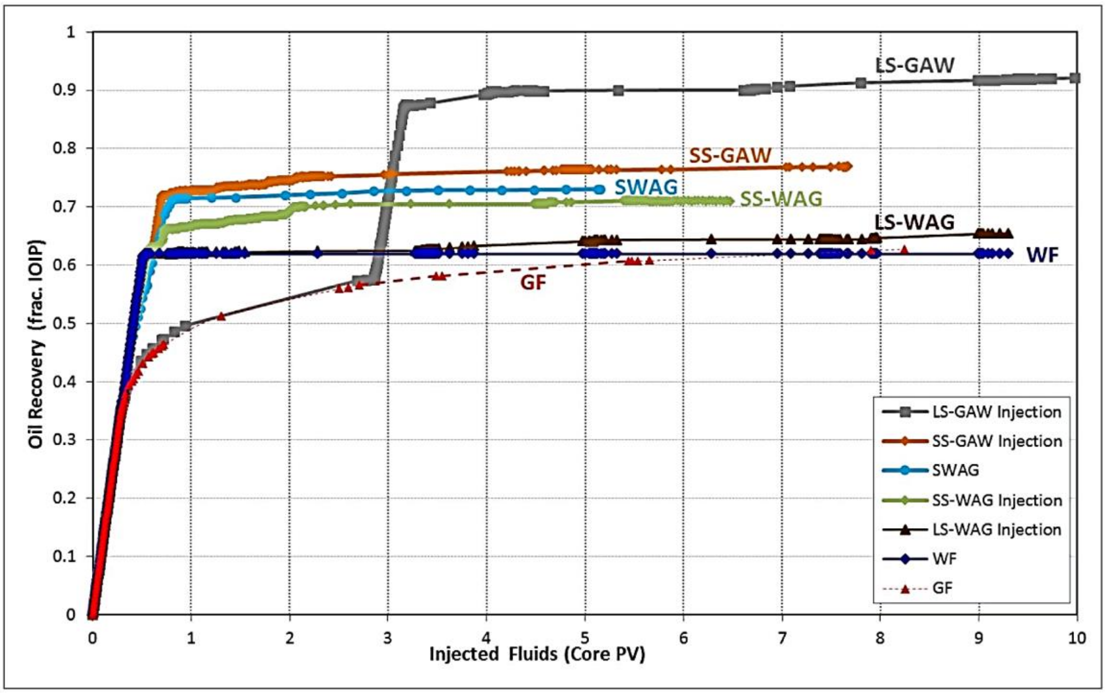


Figure III.5: Overall comparison of oil recovery versus injected PV for different water and gas injection scenarios (Alkhazmi, B. et al (2017, October)).

• Comparison of the oil recovery trend lines for SS-GAW and LS-GAW shows that even though gas breakthrough time was much shorter for LS-GAW than that in SS-GAW, due to the effect of slug size, theamount of oil recovered in LS-GAW was much higher than that in SS-GAW. This is because of the jump in oil recovery after switching the injection from gas to water during the LS-GAW injection. This oil jumpoccurred after 2.75 PVi and significantly increased the oil recovery from 56.5 % (RF %) up to 87.0 % (RF %). In real oil fields, this behavior maybe observed if water is injected in areas where gas cap has expended

• Comparing the water BT times for SS-WAG and LS-WAG injections shows that reducing the magnitudeof the injected cycles has slightly delayed the water BT time of SS-WAG (at 0.56 PVi) compared with its time in LS-WAG (at 0.53 PVi). In addition, it can be concluded that the small injected cycles, in SS-WAG injection, exhibited higher performance of oil recovery than the large extended cycles in LS-WAG injection. The cumulative oil recovery achieved by LS-WAG is 65.5 % (RF %), whereas its value from SS-WAG is 71.0 % (RF %). This demonstrates that reducing the size of the injected water slugs has significantly enhanced the oil recovery, by 5.6 % (RF %).

• Comparing the oil recovery for seven core-flood experiments including SS-GAW, LS-GAW, SS-WAG, LS-WAG, LS-GAW, SWAG, GAS Flood, and Water Flood reveals the following:

1. The large gap in oil recovery between LS-GAW and LS-WAG became narrower after reducing thesize of the injected slugs.
2. Reducing the size of the injected WAG (which started with water) had significantly enhanced the oilrecovery over the large cycle of the WAG injection
3. Although the oil bank jump was much smaller in the SS-GAW test compared to its behavior in LS-GAW, its oil recovery compares better with a possible GAW injection in an oil reservoir.
4. Although a high performance was observed of the water-flood in a mixed-wet system, the alternatingsmall water slugs with limited gas injections had much better effect on oil recovery.
5. The SWAG injection seems to be emulating the SS-GAW and SS-WAG, but with larger slugs.
6. Reducing the injected slug size appears to lead to higher oil recovery and approach the trend of SWAG injection. In other words, the oil recovery performance by SWAG injection seems to show the upperlimits of the SS-GAW and SS-WAG tests.
7. In the mixed-wet system, the slug size of the GAW test which starts with a small gas slug (SS-GAW)behaves much better than the one starting with a shorter water period (SS-WAG).

❖ The effect of the order of fluid injection and slug size on oil recovery and injectivity behavior of WAG have been investigated for a number of core-flood experiments including: SS-GAW, SS-WAG, SWAG, LS- GAW and LS-WAG injections. The following conclusion are drawn from this study:

1. Comparison of the amount of oil recovered by SS-GAW test shows that the highest oil recovery performance was obtained by the first two small size cycles of gas and water injections, which produced about 72.0 % (RF %) out of the ultimate oil recovery of 77.0 % (RF %).
2. A comparison of the amount of oil recovery by SS-WAG test shows that the most effective cycles ofwater and gas injections were the first two cycles (W1, G1, W2 and G2). About 63.40 % (RF%) out of the ultimate oil recovery of 71.0 % (RF %) was recovered by these efficient cycles.
3. Comparison of the results of the short slug water and gas injection (starting with a water injection period), with its previously reported large slug WAG injection shows that reducing the size of injected slugs significantly improve the performance of this injection strategy.
4. Comparison of the results of the SS-GAW and SS-WAG with those of LS-GAW and LS-WAG shows that the large difference in the amount of oil production which had been observed between LS-GAWand LS-WAG has become narrower after reducing the size of the injected GAW and WAG slugs.
5. The amount of oil recovery obtained by the SS-GAW (small slug WAG injection starting with gas injection) compared to that obtained by SS-WAG (small slug WAG injection starting with water injection) still shows a much better performance for the SS-GAW compared to SS-WAG.
6. Comparison of the performance of the SS-WAG and the SS-GAW with that of the SWAG test showsthat SWAG is the upper limit of oil recovery by small slug size LS-GAW and LS-WAG injections.
7. Investigating the effect of slug size for the core-flood experiments starting with gas injection periods(SS-GAW and LS-GAW) on the water injectivity reveals that reducing the magnitude of the injected cycle has only improved the water injectivity of the 2nd water (W2) injection in SS-GAW, comparedwith that in LS-GAW.[16]

III.4. The Impact of WAG cycle length

- **Description:**

For the future field development plans in Al-Shaheen HC-WAG will form a major part for the developmentof Mature Flank and Heavy Oil areas of the field. The areas proposed for WAG are under saturated with gas at reservoir conditions. The HC-WAG program aims to maximize the EOR potential in the selected areas, assuming there is sufficient gas available for injection. On-going WAG pilot has shown that there are:

Number of parameters, which potentially could affect recovery from WAG and it is important to optimizeWAG development taking into account these parameters.

The work presented in this section explores the possibility of optimizing the HC-WAG process for the future development plans. Incremental recovery from WAG could be affected by thermodynamic effects due to large variations in, permeability, viscosity and saturation pressure in the Al-Shaheen field along witha number of other variables, e.g., WAG cycle length, WAG ratios, Injected Gas compositions etc., which could potentially impact the incremental oil recovery. Besides thermodynamics effects these variables are also examined for optimizing recovery from WAG and are listed below:

1. Changing the total gas slug size (how many years is the WAG flood continued).
2. The WAG timing (when to start WAG in a particular development, i.e., how many years of water flood prior to starting the WAG).
3. The WAG cycle length (the time on gas injection plus the time on water injection prior to switchingback to gas from water). A WAG project with 6-month cycles of gas (e.g., injecting gas for a 6-month gas cycle prior to switching the well to water injection) followed by 6-month cycles of water has a 6-month gas cycle and a 12 month WAG cycle.
4. The WAG ratio (the ratio of the length of time that the well is on continuous water injection to the length of time the well is on continuous gas injection e.g., 3 months of gas followed by 9 months of water is a WAG ratio of 9/3, which is a WAG ratio of 3).
5. Impact of constraining injection wells based on producing GOR and production wells based on gas rates.
6. Improve oil recovery by choking the production wells.
7. Impact of changes to the composition of the injection gas and finally, the impact of optimizing the overall slug size of the HC-WAG.

The different thermodynamic effects from injecting gas have been examined on the sector model. The model is also simulated for different WAG cycle length (1/1, 3/3, 6/6 12/12, etc.), different WAG ratios (1:2, 2:1, 1:3, etc.) and different WAG slug sizes (1-30 years of WAG). The effects of choking productionwells, and changes in injection gas composition were also tested on the sector model.

- **RESULT:**

In managing a WAG project, the WAG cycle length, the WAG ratio, and the WAG project lifetime for eachpattern have to be properly determined. This can be done after carrying out a number of simulations based

on changing each of the variables. In order to determine the best WAG strategy for the undeveloped areas of the field, six cases are simulated with varying WAG strategies for each polygon:

1. Three months gas and three months water cycle (3:3),
2. Six months gas and six months water cycle (6:6),
3. Twelve months gas and twelve months water cycle (12:12),
4. Three months gas and six months water WAG cycle (3:6),
5. Six months gas and three months water WAG cycle (6:3) and
6. Nine months gas and three months water WAG cycle (9:3).

These WAG cycles are simulated for 3, 5, 10 and 15 years of WAG followed by water flooding for each polygon, with total simulation time of 30 years. The results are shown in **Figure III.6.** These figures show net and gross gas utilization factors along with WAG incremental oil over WF for the sector model

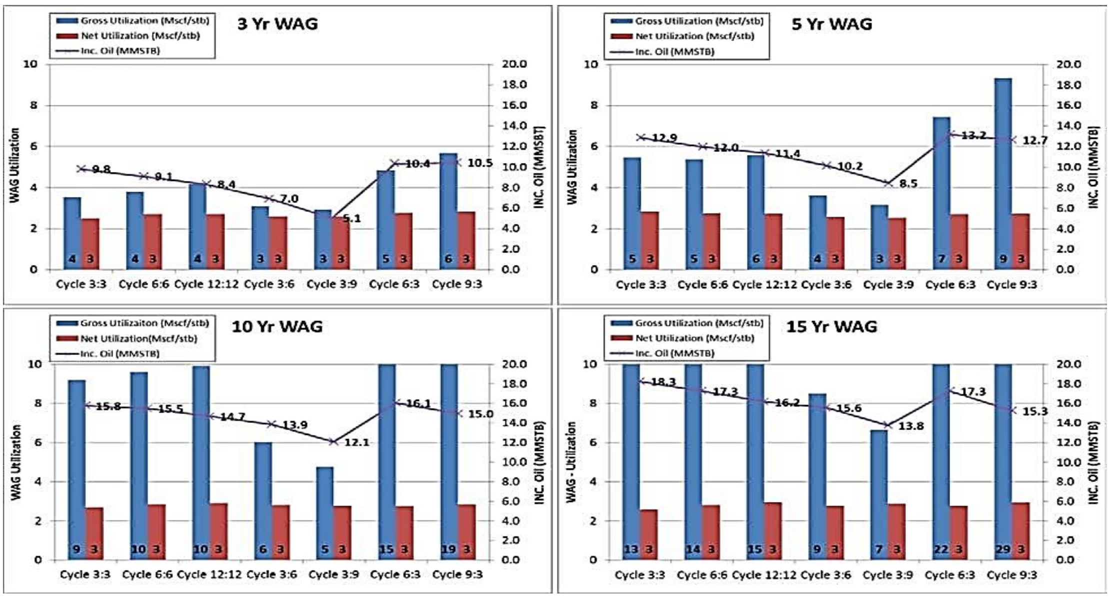


Figure III.6: Impact of different WAG cycles for 3-, 5-, 10- and 15-years WAG on KB14 polygon with no constraint on produced gas (Pal, M., et al (2018, March)).

- These cases examined different WAG cycles and different gas rate production constraints. **Figure III.7 and Figure III.8** show results of cases with a gas rate constraint of 3MMscf/d.

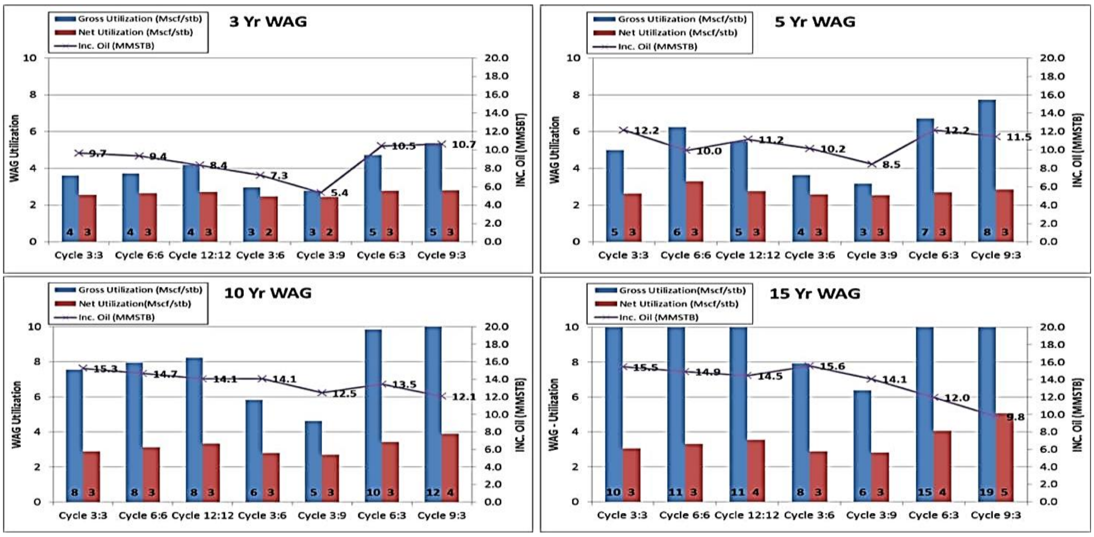


Figure III.7: Impact on sector model recovery of limiting the producers to a gas rate cut-off limit of 3 MMSCF/d with different WAG cycles for 3, 5, 10 and 15 years of WAG (Pal, M., et al (2018, March)).

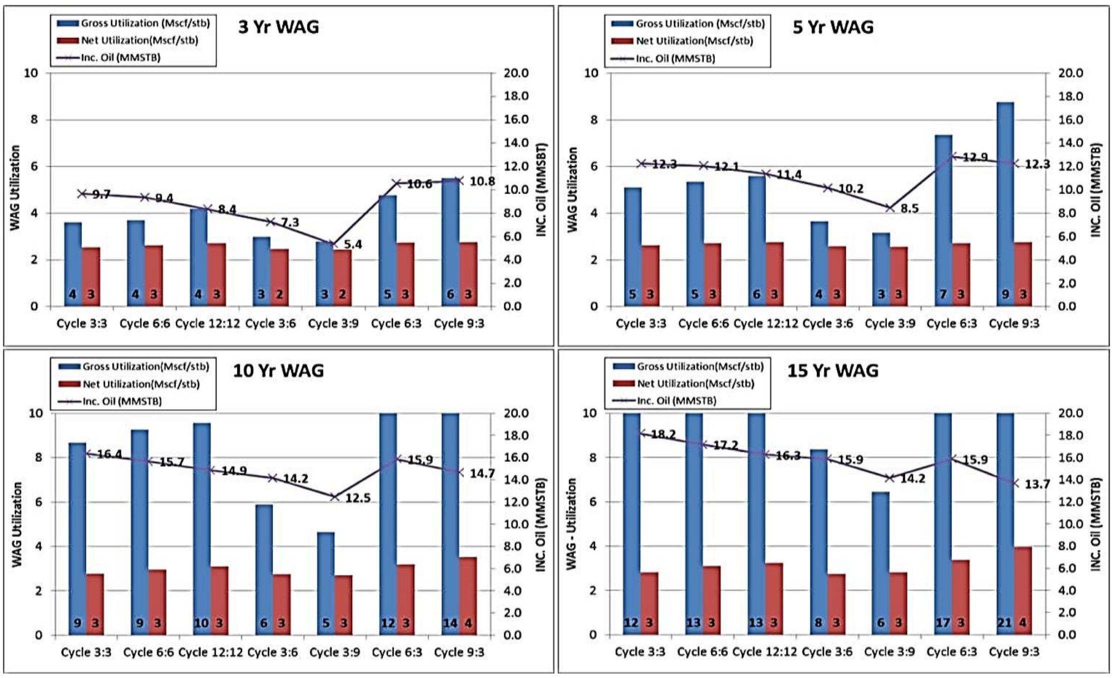


Figure III.8: Impact on sector model recovery of limiting the producers to a gas rate cut-off limit of 6 MMSCF/d with different WAG cycles for 3, 5, 10 and 15 years of WAG (Pal, M., et al (2018, March)).

❖ In this paper, WAG process was analyzed for the areas of the Al Shaheen reservoirs for future WAG developments. A number of compositional simulations were performed to determine the optimum WAG cycle length, WAG ratio, WAG timing and WAG total gas slug size. The impact of changing the production constraints, changing the start-up time of the WAG, and changing the injection gas composition were also studied. Results from these simulations can be summarized as follows:

- Sensitivities on WAG cycle length and WAG ratio (1/1, 3/3, 6/6, 12/12, 3/9 and 9/3 WAG cycles).
- Running equal ratios (a WAG ratio of 1) reduces the oscillation/variation in production rates. There is an observed incremental oil gain by reducing the cycle length (i.e., between 1/1, 3/3, 6/6 and 12/12 WAG cycles)
- Sensitivities on WAG duration (3, 5, 10 and 15 years)
- At least 5 years WAG duration is required based on standard industry guidelines for net and gross gas utilization factors. Most of the models could run for 5-10 years if these generic guidelines are used.
- Maximum gas slug sizes have been identified for the different WAG models. With a 6/6 WAG and base case economic assumptions, the WAG flood is economic for a maximum lifetime between 6 and 15 years for the different polygon.[17]

III.5. The Impact of WAG cycle number

- **Methodology:**

The experiments were performed using the in-situ core sample obtained from the reservoir and fitted in the core pack, which was then kept horizontally during all the experiments. The gas and oil samples were collected from the separator and recombined in the laboratory with given gas-oil ratio (GOR) so as to become representative of the in-situ reservoir fluid. The recombination process is discussed in detail elsewhere (Bhatia, 2010). The experiments were performed using the recombined separator fluid as a reservoir fluid in the core sample and the hydrocarbon or CO2 gas with water as a mean for injection in the core sample during WAG process. The water was injected at 20 cc/hr and gas was injected at 10 cc/hr, which remained same for all the experiments as mentioned above. The basis to choose these injection rates for water and gas are purely based on our experience of several laboratory studies done in-house to mimic the scaled-up water and gas injection rate that are possible in real field applications. The water and gas ratio remained same except for the experiments where the effect of tapering was studied.

- The **Chart III.3**; shows the composition of the hydrocarbon gas used for injection; which was obtained by using gas chromatographic technique.

Component	*Mole fraction*
N_2	0.00000
CO_2	0.02400
C_1	0.90739
C_2	0.05237
C_3	0.01310
i-C_4	0.00089
n-C_4	0.00094
i-C_5	0.00040
n-C_5	0.00048
C_6	0.00020
C_7	0.00014
C_8	0.00005
C_9	0.00001
C_{10}	0.00000
Total	1.00000

Chart III.3: composition of injection gas in mole fraction obtained by gas chromatographic **(**Bhatia, J. (2014)).

- The basic reservoir data and rock properties are given in **Chart III.4**. The given reservoir is a sandstone reservoir and is under depletion

	Details on the reservoir and the core sample	
Sr. no.	*Parameters*	
1	Reservoir rock type	Sandstone
2	Initial reservoir pressure (kg/cm^2)	292.7
3	Current reservoir pressure (kg/cm^2)	230
4	Bubble point pressure (kg/cm^2)	269.6
5	Reservoir temperature (°C)	128
6	Density of oil (gm/cc) at 128°C	0.5142
7	Stock tank oil density at 15.5°C	0.8161
8	°API gravity of oil	41.5
9	Oil FVF (v/v)	1.84
10	Specific gravity of gas	0.8364
11	Solution GOR (v/v)	222
12	Core length (cm)	20
13	Core diameter (cm)	3.8
15	Avg. permeability (mD)	323.23

Chart III.4: The basic reservoir data and core sample experiments **(**Bhatia, J. (2014)).

- **Result:**

❖ Zhang et al. (2010) observed that by increasing the number of the WAG cycles in gas-injection methods helps to get more recovery of the oil from the reservoir. The effects of WAG cycle are also studied in this work to see the applicability for the given reservoir. The results obtained are shown in **Figures III.9 and III.10 for** single cycle WAG and five cycle WAG process using HC gas. The single cycle WAG process using HC gas shows 12.74% incremental recovery (recovery obtained after the initial water flooding) and five cycle WAG process using HC gas (no tapering) shows about 17.16% of HCPV incremental recovery over the water flooding. This indicates that the number of cycles affects the recovery of HCPV. Increment in the number of WAG cycle improves the recovery for the same amount of gas utilization. However, in some of the studies it is observed that the recovery does not improve significantly even increasing the number of WAG cycles, probably due to increased water saturation and reduced discontinuity of the oil phase (Dong et al., 2005).[18]

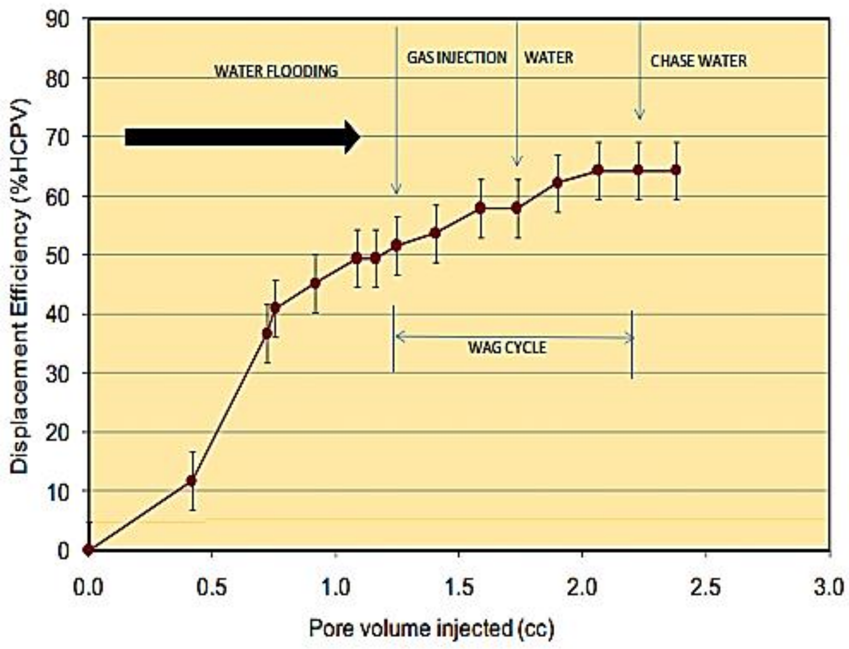


Figure III.9: Displacement efficiency vs. PV injected for single cycle WAG injection using HC gas as injectant (see online version for colors) (**Bhatia**, J. (2014)).

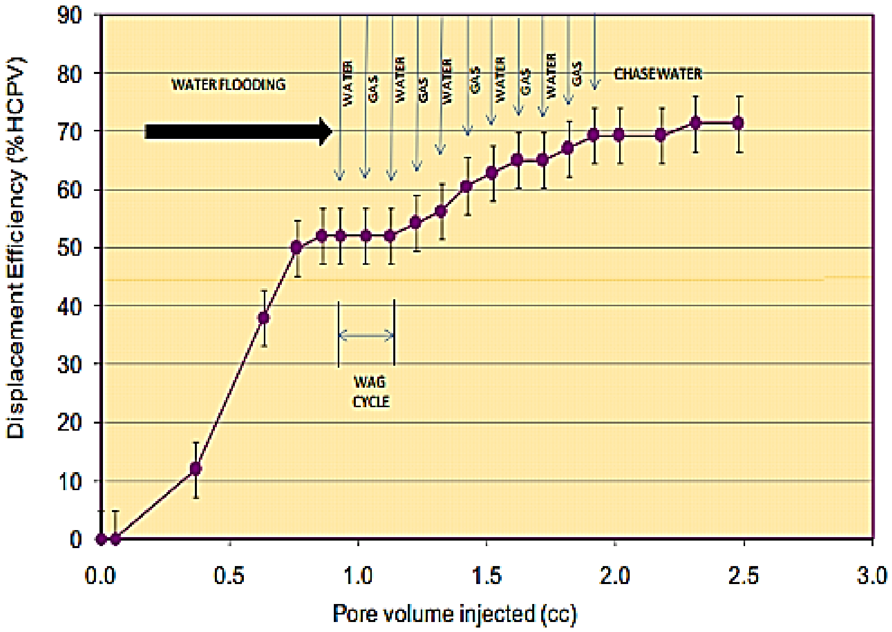


Figure III.10: Displacement efficiency vs. PV injected for five-cycle WAG injection using HC gas as injectant (see online version for colors) (Bhatia, J. (2014)).

III.6. The Impact of Selecting of the starting phase

- **Methodology:**

The aim of this study is to focus on the miscible WAG injection which is related to previous study by Abdullah and Hassan (2020) where the results need to be further improve using WAG injection after CO2 injection**. Data** were mostly collected from Geoscience Australia, and some were from Occam Technology Company. The model was constructed using the PETREL software by importing data collected. Fluid composition was obtained from PVTi program and imported into ECLIPSE software. The WAG injection was establish using data coding.

- **Result:**

- From **Figure III.11**, water was the first phase injected into the reservoir then followed with CO2injection. It shows that the oil production increased with shortest cycle time in 180 days. In this case, CO2was the first phase injected into the reservoir then followed by water injection. Five cases were also tested: 180 days, 270 days, 360 days, 450 days and 540 days. From **Figure III.12**, it shows contradicting result with **Figure III.13**, even though they showed same trend.

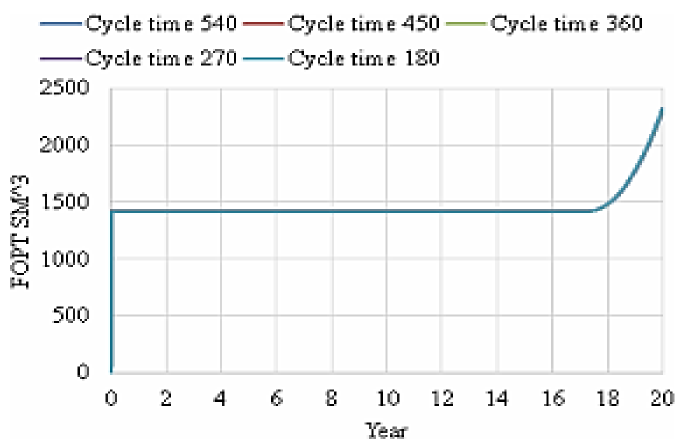


Figure III.11: FOPT versus year for WAG cycle time 180 days, 270 days, 360 days, 450 days and 540 day **(**Abdullah, N., & Hasan, N. (2021)).

- From **Figure III.12**, it shows that the oil production increased with increase in cycle time at 540 days. Since it shows that oil production increased with increase in cycle time, therefore, it proves that water was the best phase to be injected first rather than CO2. This is because oil saturation is high at the early stage of the production; therefore, it is better to inject water which has high mobility and produced more oil in an early stage. CO2are not preferable to be injected first due to its low mobility and can result in early breakthrough and viscous fingering.[19]

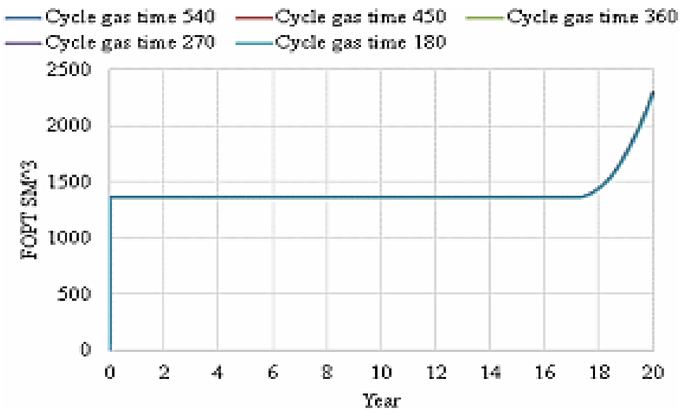


Figure III.12: FOPT versus year for WAG cycle time 180 days, 270 days, 360 days, 450 days and 540 days with gas injected as first phase **(**Abdullah, N., & Hasan, N. (2021)).

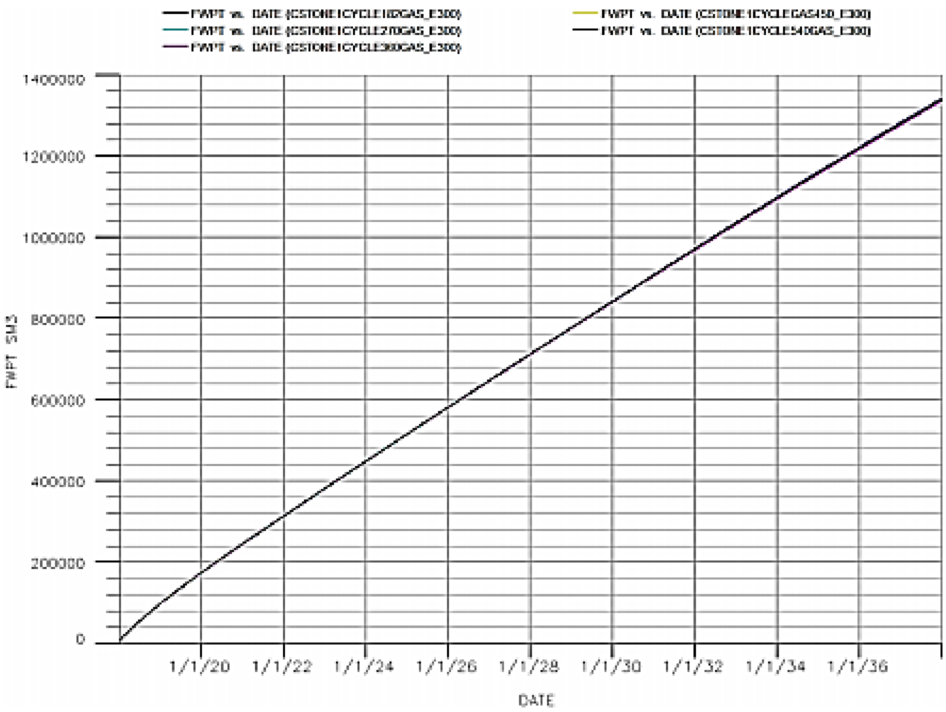


Figure III.13: FWPT VS year WAG cycle time 180 days, 270 days, 360 days, 450 days and 540 days with gas injected as first phase **(**Abdullah, N., & Hasan, N. (2021)).

Another study shows the effect of the first fluid injected.

The main purpose of this work is an investigation of the effect of parameters affecting WAG injection, and consequently the optimization of the crucial parameters of WAG process. In this study, the simulation studies are run on a synthetic model with real PVT data of the reservoir fluid in order to perform a qualitative study of the parameters which are crucial for a WAG process design by using a commercial reservoir simulator ECLIPSE 300. Firstly, a synthetic model was simulated, and then reservoir fluid was simulated by using the real PVT data.

Selecting the First Phase to Inject.

Selecting the first phase to inject in the WAG injection process is one of key parameters which must be determined. Water and gas rates were selected 2000 STB/day and 1500 MSCF/day respectively. The total injected pore volume was 0.7 PV, and water-wet rock data were chosen as the input to the simulator. Injecting water phase as a first phase produces higher recovery value than the gas phase. At the beginning of injection, the reservoir oil saturation (also the permeability of oil phase) is high enough, and this value decreases over times of injection, so it is better to use a fluid (like water) which has higher mobility than gas and can produce more oil at the early times of injection. If gas phase was chosen as the first injected fluid, then the gas breakthroughs very soon and cannot produce oil like before the breakthrough time; thus, if water was injected after gas phase, the saturation and also permeability of oil phase would be decreased, and water could not produce high oil volume in comparison with the time when water was injected as the first fluid. In the case of injecting gas as the first fluid, if the cycle time of injection was increased, it would result in low oil production after early breakthrough times. The results of these simulation scenarios are illustrated **in Figures III.14 and III.15.**

- **Figure III.14** shows the recovery comparison for several cycle times for the two conditions (W-G) and (G-W). (W-G) means injecting the water phase first, while (G-W) means injecting the gas phase first.
- **Figure III.15** shows the fraction of breakthrough time (FBT) of injection. As mentioned before, when water was first injected, FBT would be decreased, which means water very quickly reaches the producing well. When the gas was the first injected fluid, water FBT would then be increased. In this kind of injection, for the highest cycle time of injection, FWCT would be the minimum.[20]

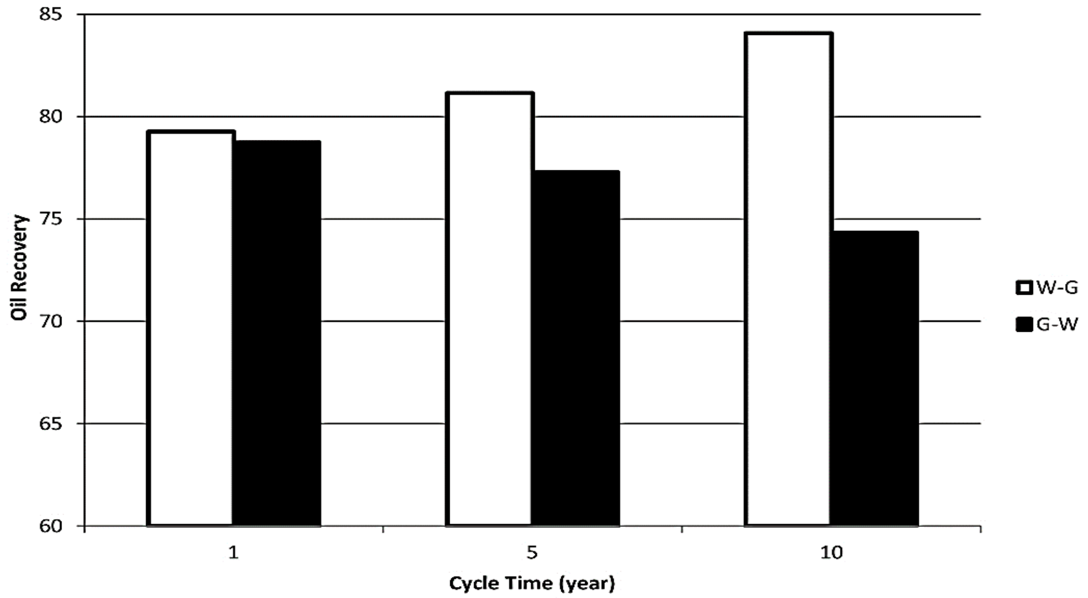


Figure III.14: Recovery comparison for several cycle times for two conditions, namely W-G and G-W in water- wet rock (Ghorashi, S. S., & Akbari, K. (2017)).

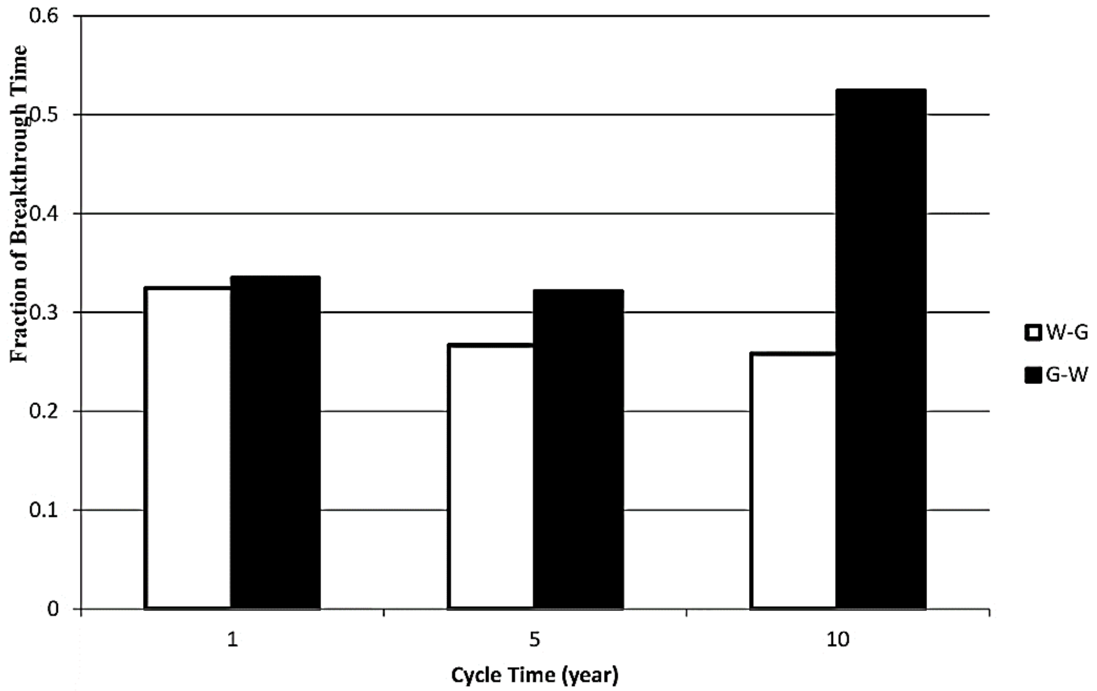


Figure III.15: FBT comparison at several cycle times for two conditions, namely W-G and G-W in water- wet rock (Ghorashi, S. S., & Akbari,

CHAPTER IV:

Impact of WAG injection on oil recovery.

❖ In this chapter, we will determine the oil recovery efficiency by WAG injection. By conducting an investigation of the performance between alternating gas and water huff-n-puff technologies in a tight oil tank.

IV.1: A comparison between WAG and water huff-n-puff technology and their impact on oil recovery:

1.1. Geological Settings of the Study Area:

Jilin oil field is located in the Songyuan district that is found in the western plains of Jilin province in China. Both development and exploration take place in the Yitong River basin and southern SongLiao Plain in the Jilin. The oil production surpassed seven million tons per year and ranked as number 9 among land-based Chinese oil fields (Liu, Yang, Feng, & Feng, 2013).

1.1.2. Reservoir Characteristics:

- **Porosity:** The reservoir porosity of the Jilin oilfield ranges from middle to low position and its value is generally between 10 % and 25 %.
- **Oil Saturation:** The original oil saturation of the oil reservoirs ranges from 47 % to 65 % in the Jilin oilfield.
- **Permeability*:*** The reservoir permeability of the Jilin oilfield ranges from ultra-low to low position, and its value is generally<50 10-3 lm2.

1.2. Water huff -n- Puff:

This is an EOR method that uses a water flooding method by which there is opening and closing of the injector/producer well in specified time intervals during the field life. This is also among the Enhanced oil recovery methods which are applied to the oil or gas industry in order to increase the field productivity and the efficiency of recovering the oil trapped in the very tight sands.

1.2.1. Water Huff-n-Puff Mechanism:

The water huff-n-puff technique is to supplement the formation energy and uses the capillary force to absorb and discharge oil in the hydrophilic reservoir. Water is injected, then sucked into the matrix and retained for some time, so crude oil needs to be driven into the relatively high permeability layers; then, Water and oil will be re-distributed. Through that process, the crude oil will be replaced by the injected Water under the imbibition effect and will be produced with the injected Water (Guowei, Xu, Lei, Meng, & Linghui, 2020).

Primarily Water improves oil recovery by the capillary force, gravity, and elasticity displacement. The huff n puff technique involves three stages, which are;

I. **Huff**.
II. **Soak**.
III. **Puff**.

These three stages can simply be illustrated in **Figure IV .1** above. Injected Water first does the job of filling the fractures and the large throats, and then after shutting the well under the capillary force achievement. The Injected Water will relocate the oil in the matrix and then open a well to recover an exchanged hydrocarbon (oil). That is why due to the oil–water imbibition mechanism, drainage and injecting are easy, which shows that water huff n puff is considered one of the effective methods to improve oil recovery. Some studies found that the oil production rate can be amplified by about 78 % during the first period of the water huff n puff cycle (Zhongxing, et al., 2015).

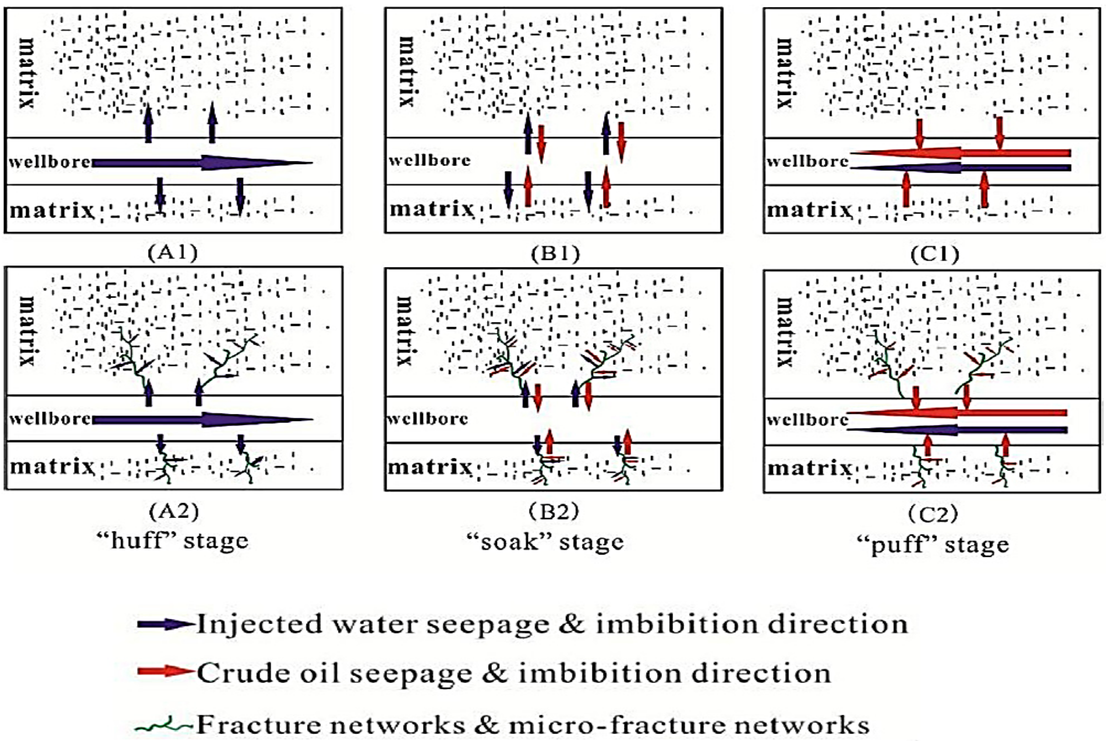


Figure IV.1: Schematic stages for huff n puff (Guowei, Xu, Lei, Meng, & Linghui, 2020).

1.3. Methodology:

1.3.1. Numerical simulation method:

For this study, ECLIPSE (Eclipse-300), as a simulator for the numerical data from the case study of the Jilin tight oil field, has been used to bring out results based on the predetermined objectives of the study. Both water alternating gas (WAG) and Water huff-n-puff models were built by the miscibility approach, which was enabled by the MISCIBLE keyword in RUNSPEC in the data file. From both WAG and Huff n puff techniques, individual models can be made and hence the following are desired results from the two models.

1.3.2. A three-dimensional model:

Both porosity (PORO) and permeability (PERM) distribution through the reservoir can be displayed through their corresponding 3d model. This can help to have a better understanding of the reservoir and its response towards recovery based on the EOR method applied so that to decide which method(s) can be applied in order to recover the oil from the reservoir. **Figure IV.2** illustrates the Field 3D model.

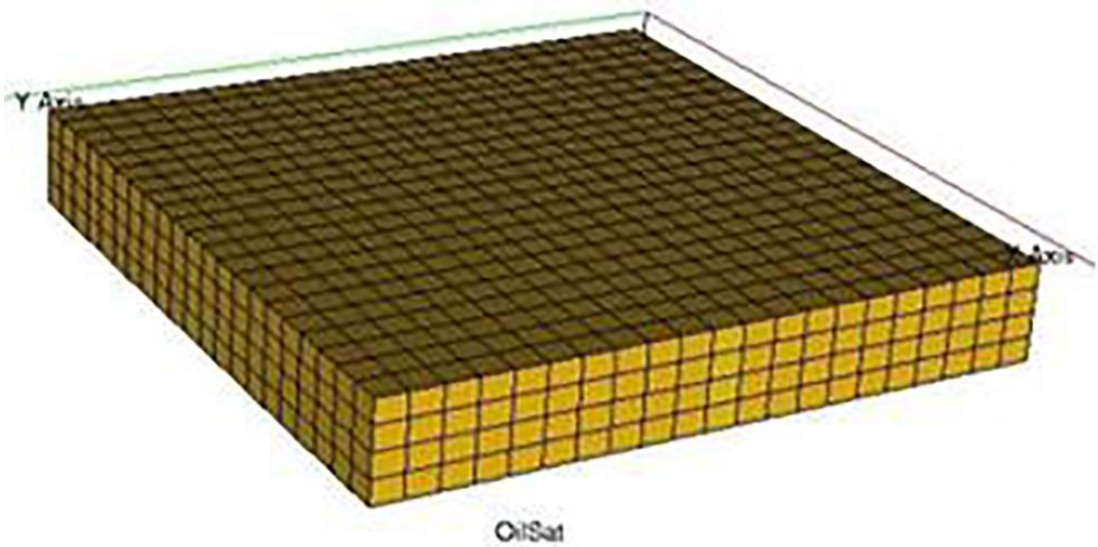


Figure IV.2: Three-dimensional models (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

Furthermore, the oil saturation distribution model can be given out from the results based on the simulated running time TSTEP, by which both of the models have a total of 2922 days of simulation. Thus, the performance of each recovery method can be determined with the aid of the well trajectories, distribution, and spacing, as well as the operational properties such as pressure, the number of cycles, and injection rates.

For both WAG and water huff-n-puff methods, the following model dimensions and properties were kept constant to compare their productivity with their corresponding keywords.

- Model grid dimensions (DIMENS) = x y z = 21 21 4
- Depths of the top face TOPS = 2353 m
- Porosity (PORO) = 0.15
- Permeability (PERM) in mDarcy = (X Y Z) = 5 5 0.5
- Constant Reservoir Temperature (RTEMP) = 97.3 C

For the WAG model, there is a total of nine (9) vertical wells, of which 8 are producer wells, namely O1, O2, O3, O4, O5, O6, O7 and O8; also, there is one injector well which alternate to inject Gas (CO_2) and Water named as G1 as shown **in Figure IV.3.**

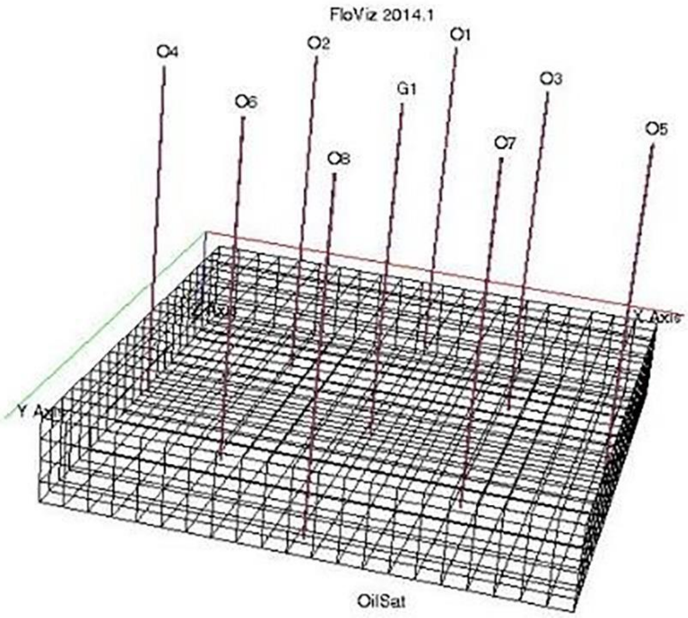


Figure IV.3: WAG three-dimensional wells trajectory model (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

For the water huff –n- puff model, there is only one vertical well by which it becomes an injector well when it is soaking time and becomes a producer well after opening it, and it is named G1as shown **in Figure IV.4.**

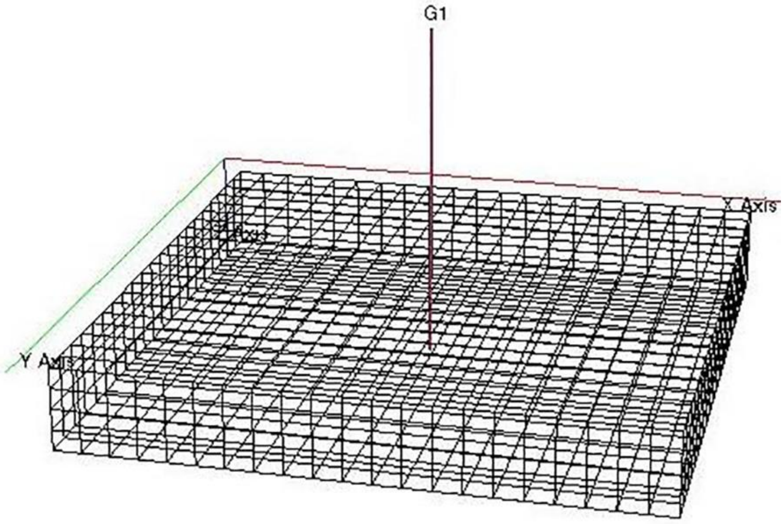


Figure IV.4: Water Huff n Puff three-dimensional well trajectory model (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

1.4. Results:

1.4.1. Oil recovery:

From the simulation of 2922 days in the reservoir for both techniques, Water Alternating Gas (WAG) and Water Huff and Puff. Individually **Figure IV.5 and Figure IV.6** display the oil recovery trend through the Field oil recovery efficiency factor (FOE), whereby the WAG technique in **Figure IV.5** has reached up to 0.465 as 46.5 % field oil recovery whereas for the Water Huff and puff technique has reached up to 0.03 as 3 % field oil recovery as displayed in **Figure IV.6.**

From the water Huff and Puff technique, from 1 day to 32 days, there is no oil production because there is soaking for that period of time. Meanwhile, from the beginning of the WAG, there is oil production with a recovery efficiency of 2.2 %, whereby there is carbon dioxide (CO_2) flooding.

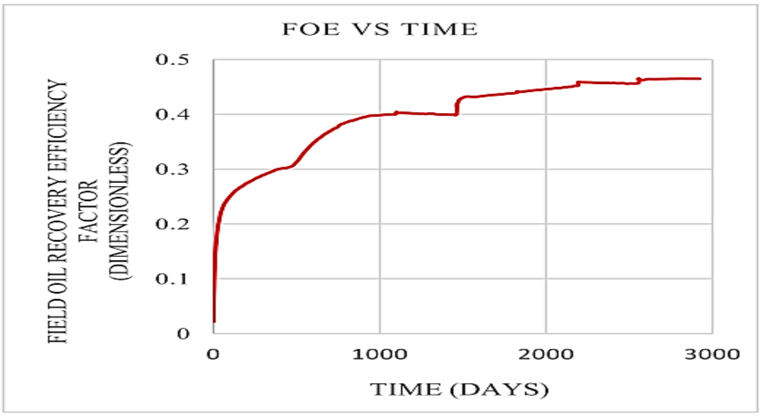


Figure IV.5: WAG Field oil recovery efficiency factor (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

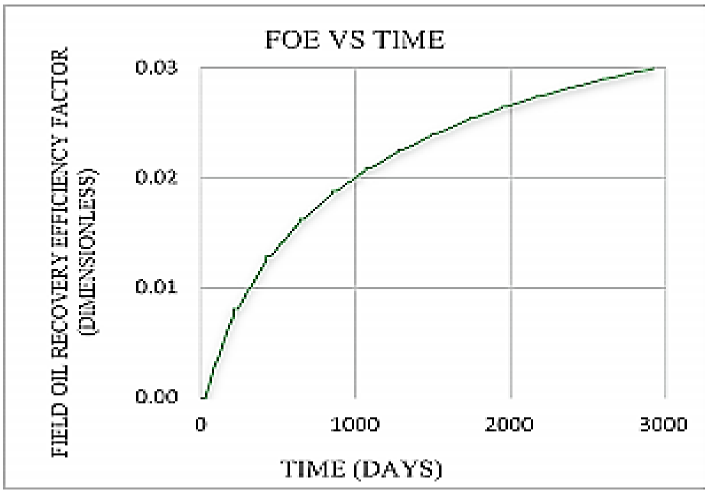


Figure IV.6: Water Huff n Puff Field oil recovery efficiency factor (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

1.4.2 Field Oil Production:

4.2.1: Field oil production Rate:

The rate of producing oil for the WAG shows a promising trend because it increases with time. On the 2557 day, it shows the peak value of the production rate of 9366 Sm3/day.

The peaks up and peak downs of the production rates show the alternating stages in the flooding types whereby the high peak implies carbon dioxide (CO_2) flooding, and the low peak implies water flooding because its sweeping rate is lower than using Gas (CO_2).

- **Figure IV.7** illustrates the field oil production rate by using the Water alternating Gas method of oil recovery. Field oil production rate by using the water huff and puff technique has a trend that is inversely proportional to the WAG technique, whereby the trends decrease with time.

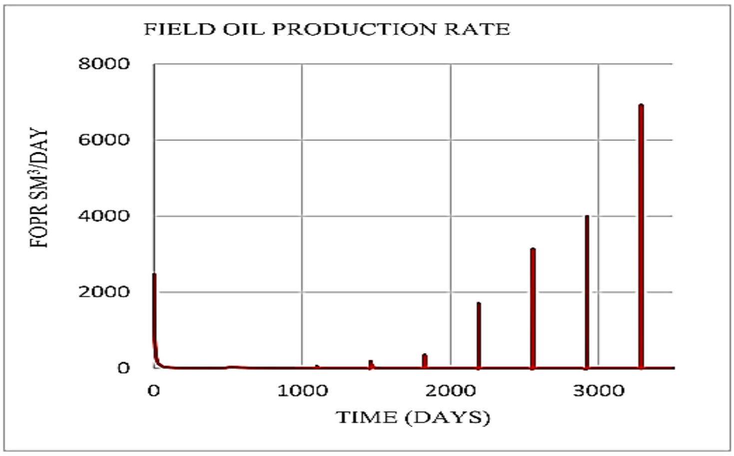


Figure IV.7: WAG field oil production rate (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

- As illustrated **in Figure IV.8** below, whereby the peak of the production rate after a soaking time on the day 32 is 6.0 Sm3/day. The sweeping water efficiency is low compared to that of Gas in the WAG that why its volumetric rates in production are quite lower than those of gas flooding.

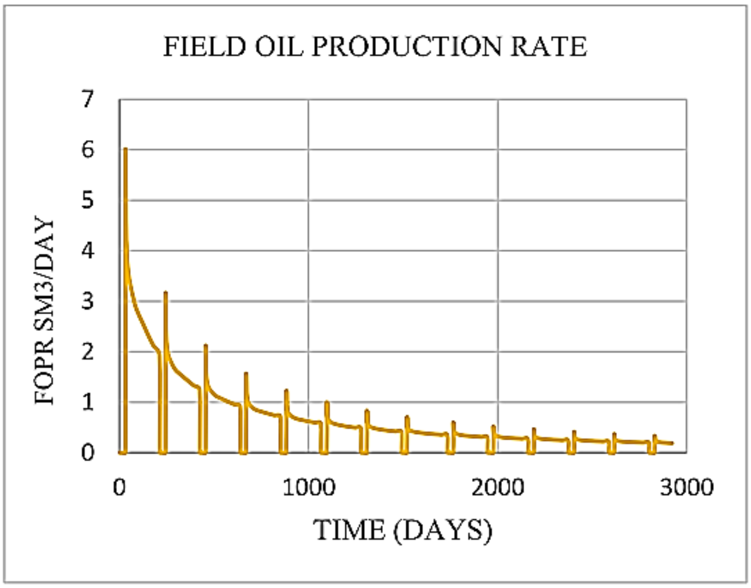


Figure IV.8: Water Huff and Puff field oil production rate (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

4.2.2: Field oil production Total

After determining the production rates, the following **Figure IV.9 and Figure IV.10** show the total oil produced for each method whereby the water alternating gas (WAG) method has produced a total of 30,453.271 Sm3, and the Water Huff and Puff method has a total field oil production of 1,726.389 Sm3 as each by 2922 days of simulation of the reservoir. There is a bit big difference in the number of the total oil produced because the rate of production using WAG is higher than the rate of production using just Water as a flooding medium, as previously explained.

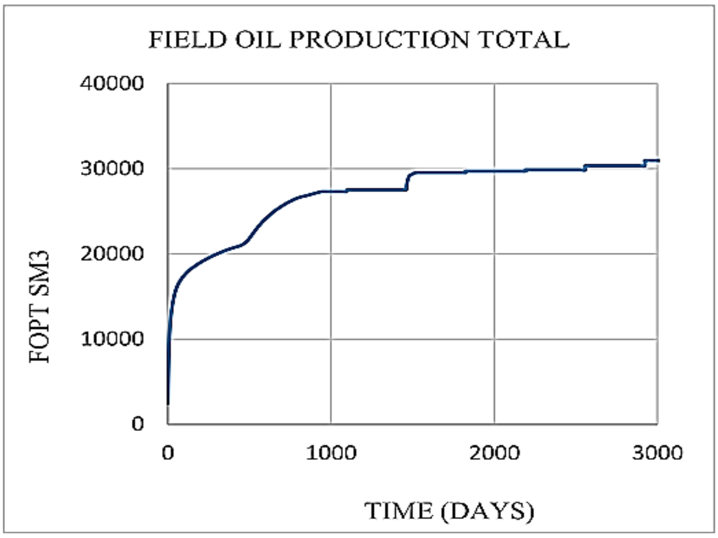


Figure IV.9: WAG Field total oil Production (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

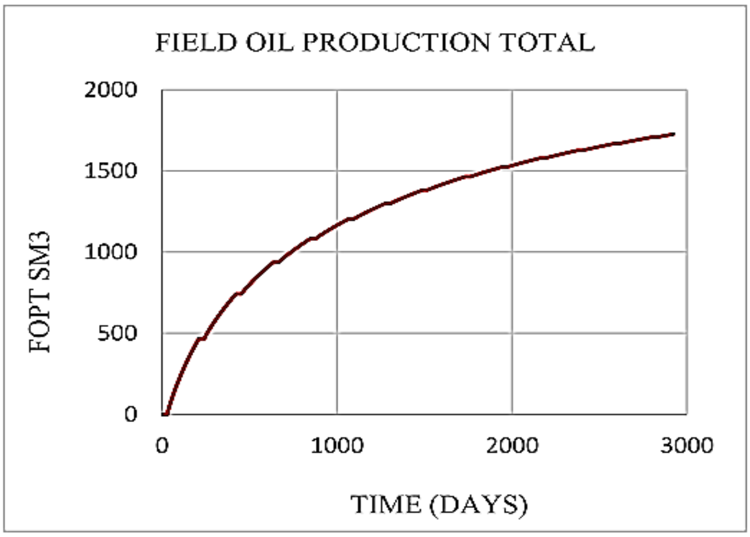


Figure IV.10: Water Huff –n- Puff Field total oil Production **(**Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

4.2.3: Field Water cut analysis for WAG and Water huff-n- Puff:

The Water cut produced from the beginning of day 1 for WAG and water huff and puff injection was 8.9 % and 7% respectively, as illustrated in **Figure IV.11 and Figure IV.12 .**

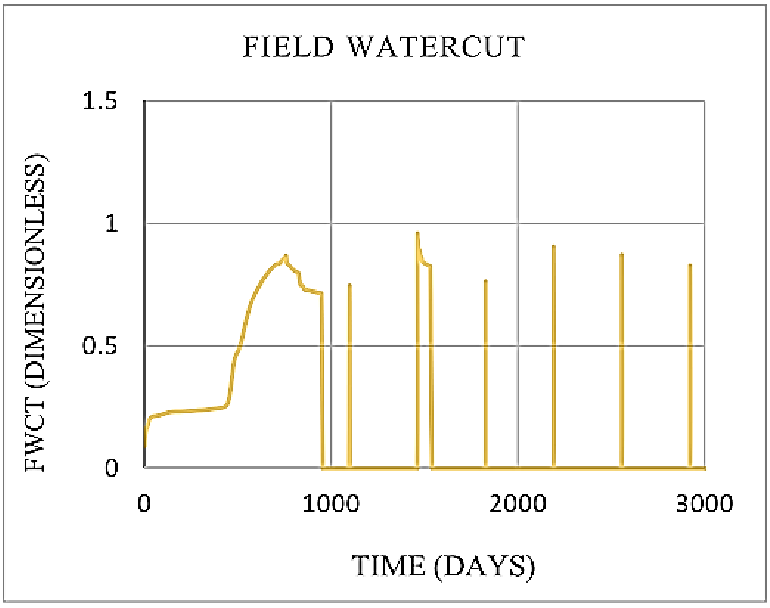


Figure IV.11: WAG Field water Cut **(**Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

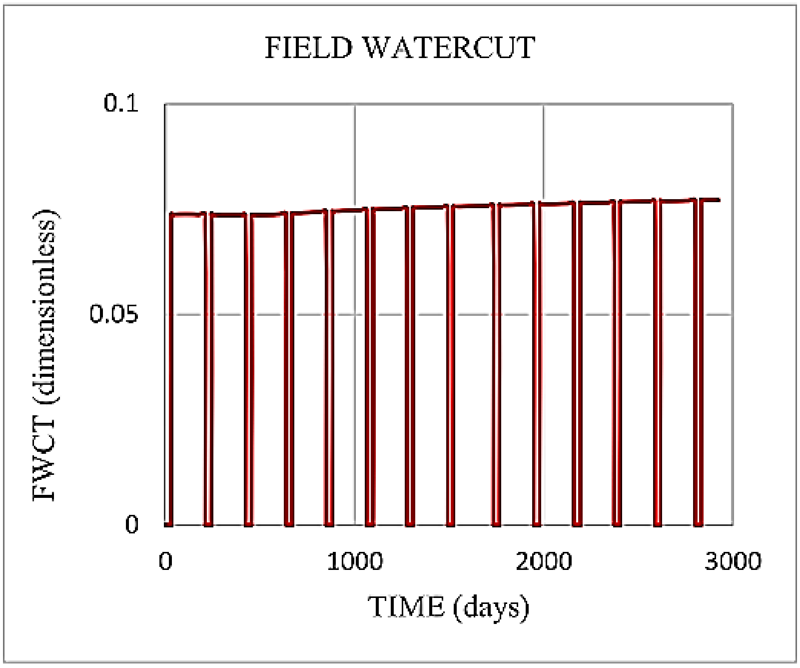


Figure IV.12: Water Huff n Puff Field water cut **(**Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

The level of water Cut produced from the WAG reached the maximum point of 96 % on day 1462 of the simulation, while that of Water huff and puff reached a maximum of 7.7 % on day 2922 of the simulation. This implies that the edge water near the well was effectively controlled in water huff and puff than of that in Water alternating gas.

This situation is emphasized by the fact that there is a shut period during the soaking time for water h-p, which there is Water lost within that period, and then the water cut could be reduced. On the other side, the WAG and water h-p field produced water total of 46157.715 Sm3 and 138.874 Sm3 after 2922 days of simulation, respectively, as in **Figure IV.13 and Figure IV.14.**

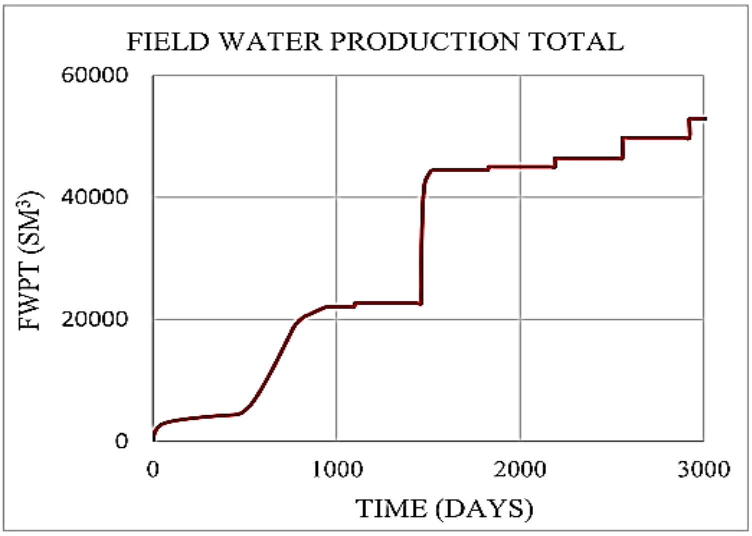


Figure IV.13: WAG water production total **(**Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

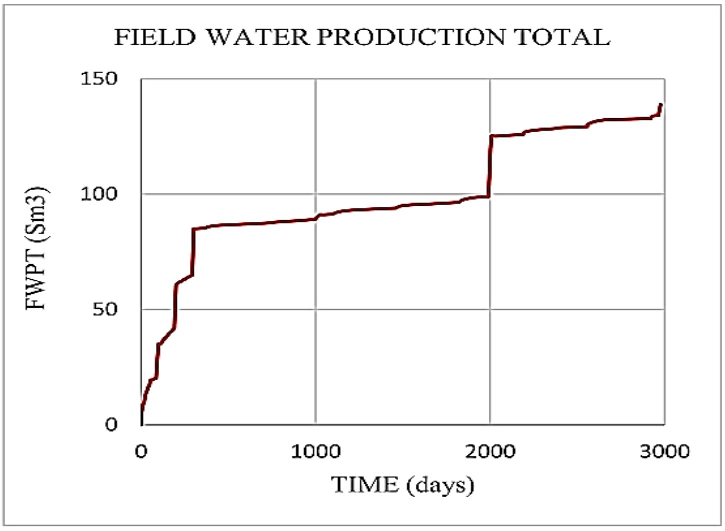


Figure IV.14: Water Huff- n- Puff Field water production total **(**Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

1.4.3. Field oil saturation Investigation:

4.3.1: WAG field oil saturation Investigation:

Initially, the average oil saturation of the field was 0.60, which is clearly displayed in the 3D model in **Figure IV.15** for both Water alternating gas and Water huff n puff methods. After 2922 days of simulation for WAG, the average field oil saturation became 0.30 with very low saturation values in the near-surface layer of the reservoir, as displayed in **Figure IV.16 and Figure IV.17,** which shows that there is high sweeping efficiency in the middle near the producer wells model, leaving some fewer amounts of the oil on the end corners of the model.

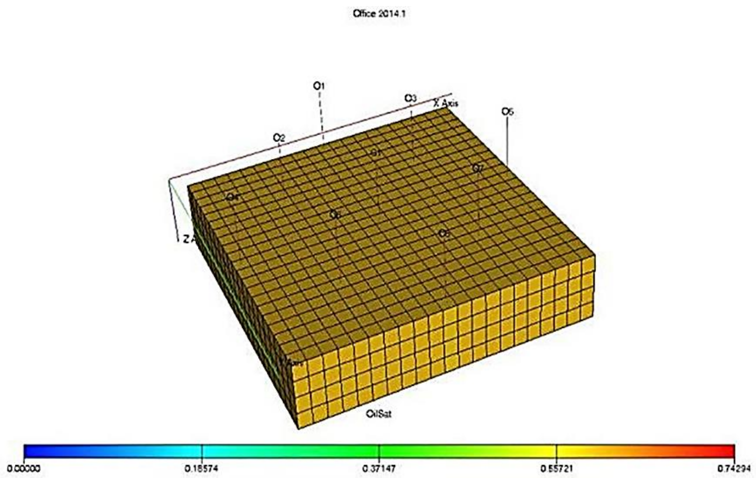


Figure IV.15: Initial oil saturation **(**Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

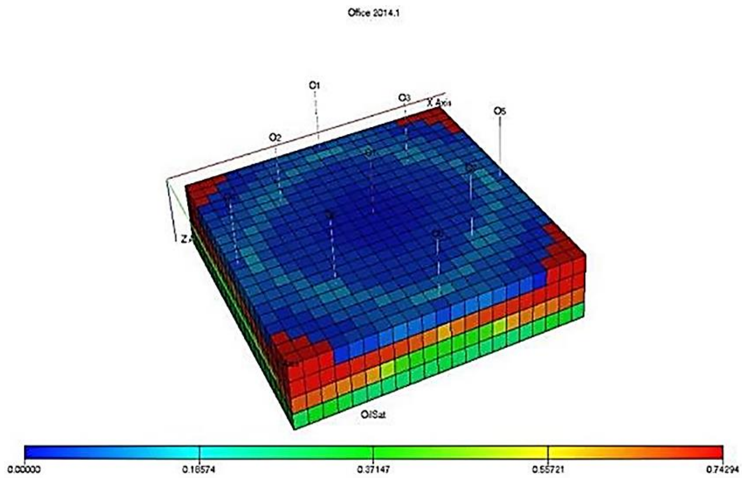


Figure IV.16: Final oil saturation **(**Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

The use of Gas (carbon dioxide) in the WAG technique has increased the oil mobility, which then embraces the sweeping when also applying the water flooding during the alternating process, hence causing the easy movement of the oil from the subsurface. Besides that, that the model has shown that there is still a substantial amount of remained in the reservoir with 30 % oil saturation model.

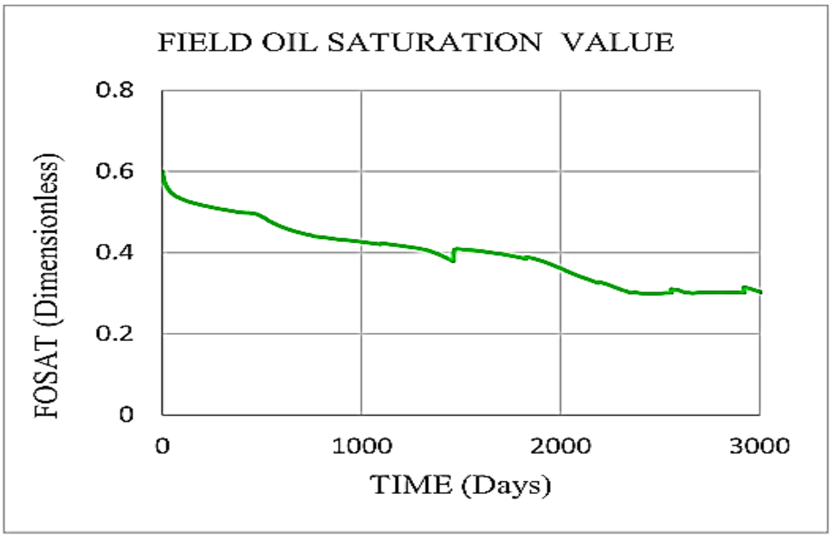


Figure IV.17: WAG Field oil saturation value **(**Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

4.3.2: Water Huff and puff field oil saturation Investigation:

On the Water huff n puff method, after 2922 days of simulation for the model, the average field oil saturation became 0.59, as illustrated in **Figure IV.18**. This implies that throughout the whole time, there is still the highest amount of oil located in the reservoir, as initially, the oil saturation was 0.60.

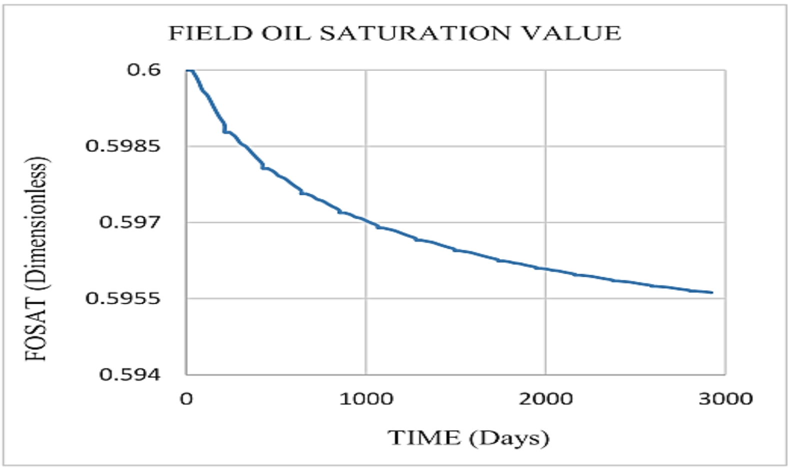


Figure IV.18: Water Huff- n- Puff field oil saturation value (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

The 3D model in **Figure IV.19** below shows that the oil has been only swept from the very bottom of the reservoir to near the top of the surface, which still indicates that there is a high amount of oil located near the surface with substantial oil saturation. The sweeping efficiency of Water through the Huff and Puff method has shown that result which, when compared to that of WAG, is quite far lower.

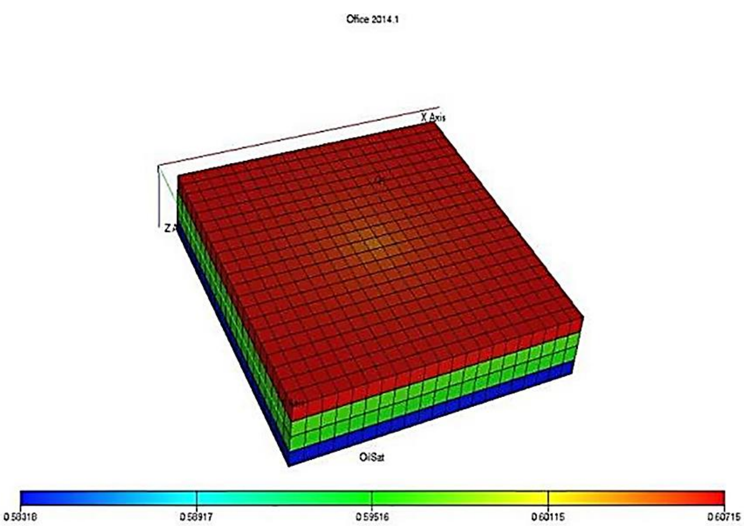


Figure IV.19: Water Huff-n- Puff final saturation (Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

1.4.4. Field oil recovery efficiency for different WAG injection modes:

After the earlier comparison of the efficiency in oil recovery between the two methods as, the water alternating gas method with that of water huff and puff, most of the results have shown that Wag is the most optimum method for oil recovery for the tight reservoir. Based on the Wag method, therefore, the four different injection modes have been tested to decide which one could give the most optimum recovery of oil.

The first mode used is named MODE 1 whereby is an injection mode starting with gas injection (CO2) followed by water injection for a 1-year cycle each; the second mode is namely MODE 2 whereby is an injection mode starting with gas injection (CO2) followed by water injection for 4 years cycle each.

The third mode used is named MODE 3 whereby is an injection mode starting with water injection followed by gas injection (CO2) for a 1-year cycle. Lastly, the fourth mode used is named MODE 4 whereby is an injection mode starting with water injection followed by gas injection (CO2) for 4 years cycle, with all being simulated by 8 years as the production.

Figure IV.20 above shows the field oil recovery efficiency for different wag injection modes. In the first years' both MODE 1 and MODE 2 have shown almost similar recovery performances, with 29.79 % and 29.74 %, respectively. Meanwhile, in the beginning, MODE 3 and MODE 4 have 34.42 % and 33.92 %, respectively. At the end of the 8th year, the results are quite dissimilar, with MODE 1 and MODE 2 being with recovery efficiencies of 46.47 % and 35.82 %, respectively; on the other side, MODE 3 and MODE 4 has 47.40 % and 43.26 % respectively. In the comparison of both of the four injection modes, MODE 3 clearly shows higher performance in the oil recovery than all other three modes as it is an injection mode starting with water injection followed by gas injection (CO2) for 1-year cycle each.

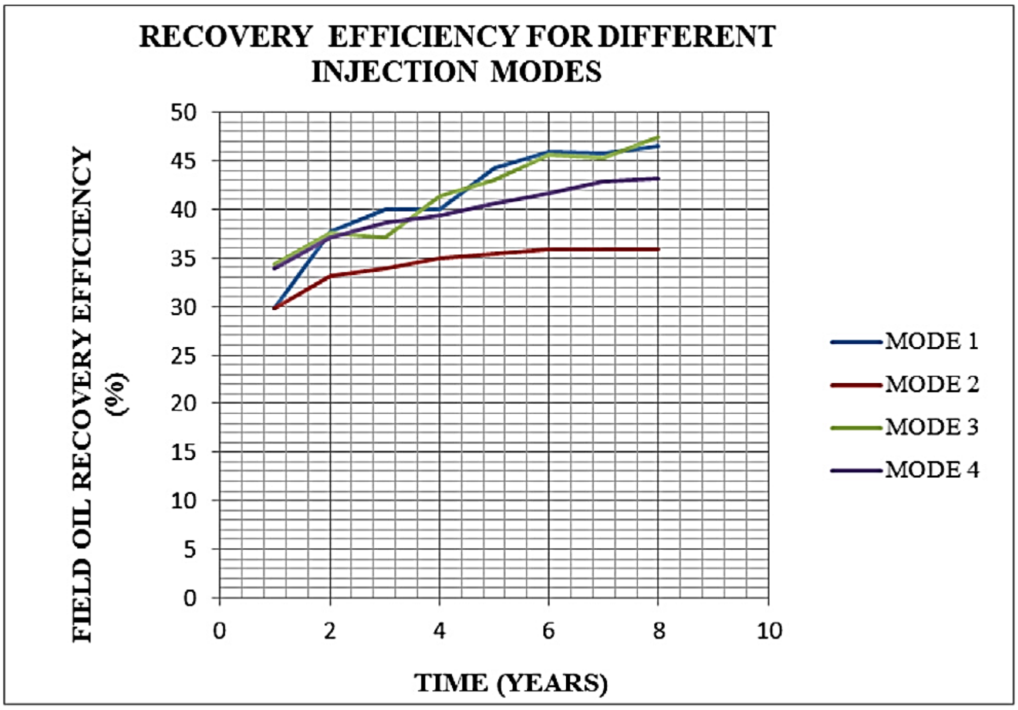


Figure IV.20: field oil recovery efficiency for different wag injection modes **(**Mohamedy, T., Yang, F., Mbarak, S. S., & Gu, J. (2022).

❖ Finally, from the designed model after the simulation of 2922 days for both of the enhanced oil recovery methods for Water alternating gas (WAG) and water huff-n-puff based on the case study of the Jilin tight oil reservoir, the following can be concluded:

1. WAG produced very promising results compared to that of the water huff and puff by generating 30,453.271 Sm3 of the total field oil, and the Water Huff and Puff method has a total field oil production of 1,726.389 Sm3.

2. WAG seems to be leading due to its higher oil recovery by having a recovery factor of 46.5 % field oil recovery, whereas the Water Huff and puff technique has only 3 % field oil recovery.

3. On the Water cutting part, it shows that the WAG method has produced more Water with 46157.715 Sm3 while the water huff-n-puff has only produced total field water of 138.874 Sm3 for the whole simulation. Then, it can be settled that the water huff-n-puff method of oil recovery has a higher capacity to reduce water injection compared to the water alternating gas (WAG) method.

4. On the deep WAG part, the best mode, which shows an optimum oil recovery efficiency of 47.40 %, is MODE 3, which is an injection mode starting with water injection followed by gas injection (CO_2) for a 1-year cycle each. Therefore, this is the Water alternating gas (WAG) method of enhanced oil recovery can be the best solution for the oil recovery for the tight oil reservoir.[21]

CONCLUSION

CONCLUSION

❖ In this thesis, we tried to investigate the impact of Water Alternating Gas injection on the ultimate oil recovery factor, through several studies based on laboratory experiments and field simulation, In addition to a comparison between WAG and the huff-n-puff method.

Based on the studies of different parameters affecting the WAG process, it is concluded that:

- The higher the horizontal and vertical permeability, the higher the initial oil production rate under the WAG injection process.
- The lower oil density will have higher mobility and flow with low resistance whereas higher oil density will have lower mobility and flows with a high resistance that leads to higher recovery.
- Carbone dioxide is miscible with oil at low pressures, so by using this gas in the WAG injection process, the highest recovery will be achieved.
- Three-phase permeability hysteresis models lead to much larger recovery predictions.
- Increasing the WAG ratio enhances the performance of the WAG process by improving the volumetric sweep efficiency.
- By increasing the cycle time of injection, recovery increases; however, increasing cycle time causes high water production, so the optimum value of cycle time must be found.
- If water is first injected, recovery will be higher compared to when gas is first injected.
- Increasing the number of the WAG cycles helps to get more recovery.
- Reducing the size of injected slugs significantly improves the performance of this injection strategy. (Starting with a water injection period).
- after the simulation of 2922 days for both of the enhanced oil recovery methods for Water alternating gas (WAG) and water huff-n-puff based on the case study: the result shows that the Water alternating gas (WAG) method of enhanced oil recovery can be the best solution for the oil recovery for the tight oil reservoir.

Recommendation

- For effective recovery efficiency to be achieved, the slugs of water and gas injected must be controlled. Too much of water will negatively impact the microscopic efficiency and too much gas will result to poor macroscopic sweep efficiency.
- WAG injection may be considered in Reservoirs with high oil viscosity, if the reservoir contains heavy or highly viscous oil, WAG injection can help improve displacement efficiency by reducing oil viscosity and enhancing sweep efficiency. Also, in reservoirs with gas-cap drives, implementing WAG injection can help maintain reservoir pressure, prevent early gas breakthroughs, and enhance oil displacement.
- WAG injection is often beneficial in reservoirs with complex geological formations and heterogeneity. The alternating injection of water and gas can help mitigate reservoir heterogeneity effects by improving fluid sweep and increasing contact with the remaining oil saturation.

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