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# Selection of A Suitable Oil Recovery Mechanism for A Niger Delta Field

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***Abstract- One of the most significant challenges for extending production life in mature waterflood fields is high water cut. Couple with high reservoir heterogeneity, extensive layering and faulting, these fields often developed irregular flood patterns after decades of production which compounded the challenge of optimizing recovery from these fields. The severity of this problem has been observed in the Niger Delta oil fields, where several matured fields are producing at high water cut after many years of waterflooding. This study aimed to improve oil recovery using Water Alternating Gas (WAG) injection in comparison with Waterflooding and Gas injection methods in the Niger Delta. Water- alternating-gas (WAG) injection process is one of innovative and new enhanced oil recovery (EOR) methods. This method Improves gas injection microscopic and water injection macroscopic displacement processes. In this study, a computer software known as "ECLIPSE" was used to model and simulate the hydrocarbon flow of an oil field in the Niger Delta. The software was used in optimizing oil recovery using WAG method in comparison with water flooding and gas injection was discussed. From the results obtained, WAG injection had a maximum field oil efficiency (FOE) of 34%, a field oil production total (FOPT) of 76.46 MMSTB, a plateau time of 3.7years and a field water cut (FWCT)of 26.11%. Waterflooding had a FOE of 26.65%, a FOPT of 59.62 MMSTB, a plateau time of 2.2years and FWCT of 47.58%. Whereas gas injection had an FOE of 21.35%, a FOPT of 47.89 MMSTB, a plateau time of 2 years, and FWCT of 9.2%. From comparative analysis of the three recovery methods, WAG injection outperformed both waterflooding and gas injection with the highest FOE of 34%, the longest plateau time of 3.7years, and a minimal water cut of 26.11%. Therefore, WAG recovery method has thus far demonstrated to be the most effective recovery method, in comparison to waterflooding and gas injection methods***

***Indexed Terms- Water Alternating Gas; Waterflooding; Gas Injection; Oil Recovery.***

## I. INTRODUCTION

Crude oil is a naturally occurring resource which comes in many forms, the most familiar form being the light crude oil, which is less dense than water and flows easily at room temperature. One of the world's main hydrocarbon provinces, the Niger Delta, has an estimated 25 billion barrels of oil and 256 trillion cubic feet of natural gas in reserve, Allison and Mandler, (2018) The Niger Delta, which is in the Gulf of Guinea, covers an area of roughly 75,000 km2, and its clastic sequence has sediments with a maximum thickness of 9,000 – 12,000 m, Adedosu and Sonibare, (2005). The Benin formation, Agbada formation, and Akata formation are the three main lithostratigraphic units that make up the thick sedimentary succession in terms of stratigraphy, as shown in Fig.1

The upper coastal plain or alluvial depositional habitat of the Niger Delta complex is known as the Benin Formation. Fluviatile gravels and sands make up the majority of its composition. It is over 1820 meters thick. The Agbada Formation, which is of fluvio-marine origin and rests beneath the Benin Formation, is mostly composed of alternating sandstones and shales. A maximum thickness of roughly 4500 meters can be found in these sands, sandstones, and marine shales that make up the Agbada Formation. Within the Niger Delta complex, the Akata Formation is the lowest unit. Since it was dumped in a normal marine setting, it is made of over pressure marine, Short and Stauble, (1967).

Most of the Niger Delta's hydrocarbon habitat is found in the Agbada Formation's sandstone reservoir, where it is typically trapped in roll-over anticlines connected to growth faults. The reservoir sands, which range in

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thickness from 10 to 20 meters, are between the Eocene and Pliocene in geological time. Medium light oil with API gravities ranging from 30 to 4500 is primarily produced in the Niger Delta. The gas oil ratios (GORs) of the lighter crude oils, which range from 180 to 1600 ft3/bbl, are variable, Adedosu and Sonibare, (2005).

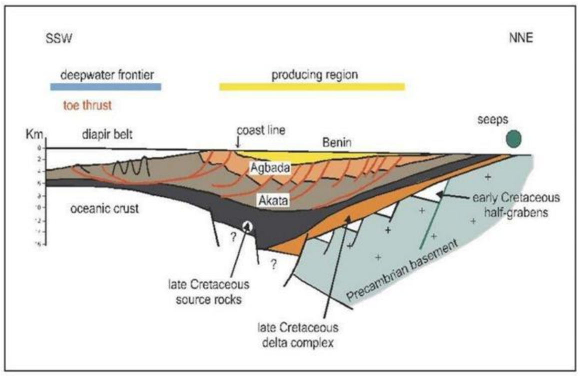


Fig: 1 Structural section of the Niger Delta Complex showing Benin, Agbada and Akata formations, Short and Stauble, (1967)

With the continuous rise in energy demand, optimizing oil production becomes crucial to meet the energy demand. The requirement for tertiary oil recovery techniques arises from the fact that the mobility of crude oils decreases to the point where standard pumping techniques are unable to achieve any flow from the well bottom to the wellhead. Crude oil production can be increased using technology and oil recovery methods, Ramasamy, (2019).

The recovery of crude oil can be grouped into three;

- Primary recovery method
- Secondary recovery method
- Tertiary recovery method

Primary recovery basically uses the natural energy drive or drive mechanisms present in the reservoir for hydrocarbon production. However, due to the lack of natural drive energy in most reservoirs, supplemental energy sources were used to keep reservoir pressure constant. These artificial drives included the injection of water or gas, Tarek, (2010).

Secondary recovery method mainly involves water flooding or gas injection. It is a technique that supplements the natural reservoir energy by injection of fluids (water or gas), primarily for pressure maintenance. When the volumetric rate of production is equal to the volumetric rate of fluid replacement in the reservoir, pressure maintenance is achieved in oil production, keeping the average reservoir pressure constant.

Tertiary recovery, also known as enhanced oil recovery (EOR), entails injecting fluids into the reservoir while applying methods for improvement other than only providing external energy to help with crude oil recovery. When primary and secondary recovery techniques are insufficient for achieving maximum oil recovery, EOR is mostly used for incremental production. The fluid parameters and reservoir features determine the type of EOR technology used for a particular reservoir, John, (2020).

A typical tertiary oil recovery technology known as the Water Alternating Gas Injection process (WAG) is used to increase the displacement efficiency of the leftover oil that cannot be recovered during the primary and secondary recovery procedures, Vishnu, et al., (2019). It is an enhanced oil recovery (EOR) technique that increases oil recovery effectiveness by combining gas injection with water flooding. The method was developed to improve the efficiency of the macroscopic sweep in gas injection procedures. It is stated that 80% of the United States of America (USA) WAG injection field projects are productive, and the WAG injection method is currently a recognized technology in total oil recovery enhancement by the re-injection of produced gas in water injection wells in an oil field, Shokufe, (2018).

In this study, the Water-Alternating-Gas Injection (WAG) recovery method is used to determine the recovery performance of a selected oil field in the Niger Delta in comparison to waterflooding and gas injection recovery method.

Mechanism of WAG Technique

The oil and gas industry has long been interested in the relatively established oil recovery method of Water-Alternating-Gas (WAG) injection because of its successful results. The method was initially used by Mobil in a sandstone reservoir in Alberta, Canada, in 1957 as a mixture of two traditional recovery techniques: gas injection and water flooding. The major objective of the WAG projects is to manage mobility and reduce the issue of viscous fingering, resulting to better oil recovery. Re-injecting generated gas into water injection wells in an oil field is part of the procedure, which is done to increase the sweep efficiency of water flooding and the oil displacement efficiency of gas injection operations, Shokufe et al., (2018).

As oil supplies are being used up more quickly, enhanced oil recovery (EOR) techniques have attracted a lot of attention recently. The water injection technique is the major approach used to extract oil from reservoirs; nonetheless, it is regarded as the least preferred technique because a significant proportion of oil still stays in the rocks. If gas injection is carried out afterwards, the residual oil can be recovered. However, it was discovered that alternating water and gas injections could enhance the recovery of the residual oil, which is what WAG technique is for,Vishnu et al., (2019). Oil recovery by WAG injection has been linked to contact upswept zones, by making use of the separation of gas to the top or the accumulation of water toward the bottom. Since the left over oil after gas flooding is often lower than the residual oil after water flooding and three- phase zones may get lower remaining oil saturation. By combining superior mobility control and contacting un-swept zones, WAG injection has the potential to boost microscopic displacement efficiency and improve oil recovery, Scrivastava and Laxminarayan, (2012).

In order to maximize and enhance oil recovery, WAG injection technique combines the improved macroscopic sweep efficiency of water flooding with the increased microscopic displacement of gas injection. The displacement is stabilized and mobility control is increased by alternately injecting gas and water slugs. Oil displacement by gas is more efficient on a microscopic scale than by water, while oil displacement by water is more efficient on a macroscopic scale than by gas,

WAG technique is divided mainly into two types;

- Miscible displacement process
- Immiscible displacement process

With the miscible displacement technique, the reservoir oil and injection gas combine into a single phase, considerably increasing oil recoveries. Due to the low viscosity of the fluid and certain reservoir conditions and oil density, the injected gas and oil will completely mix inside the reservoir, reducing the interfacial tension between the two materials. As a result, oil displacement, transportation, and production will all be enhanced. CO2 is commonly used for this process.

In an immiscible displacement process, the injected gas does not mix with the oil because the pressure is too high and the density is too high. It causes the oil to expand, which lowers its density, increases its mobility, and expands the recovery. For immiscible displacement, flue gases, nitrogen, or similar petroleum gases are used. The gas injected into the well expands like a compressed spring, displacing oil to the producing wells, similar to how gas behaves in gas cap drive mode, Abdalla et al., (2014).

High pressure compressors are needed for gas injection in the WAG process, which typically involves injecting an immiscible gas in an alternating pattern with water. Oil recoveries are lower in the immiscible gas injection procedure than they are in the miscible gas injection method because the injection gas and the reservoir oil remain in two different phases.

The WAG injection method is an effective oil recovery technique for maximizing total oil recovery; by combining the advantages of Gas Injection (GI) and Waterflooding (WF), as shown in Fig.2. Using a compressor, the gas is injected into the reservoir alternatively with the water using a pump through the injection well. In the reservoir, the injected fluid increases the oil displacement and sweep efficiency, resulting in an improved oil recovery to the production well.

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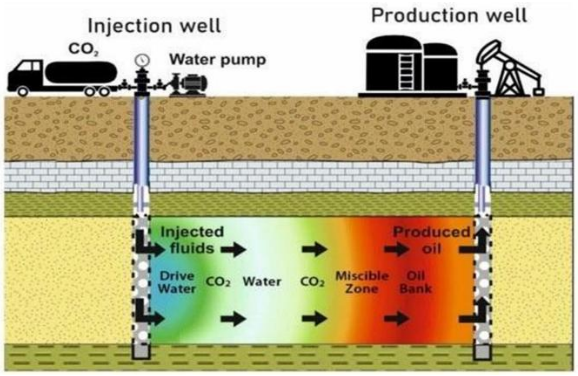


Fig 2: Schematic Representation of Water-Alternating-Gas Injection, Miroslaw et al., (2022).

## II. RELATED WORKS

Nurafiqah and Nurul, (2021), worked on the Implementation of Water-Alternating-Gas injection to obtain Optimum Recovery in Cornea Field, Australia. They employed the two- phase hysteresis model and the two-phase boundary imbition and drainage relative permeability models (Stone 1 and Stone 2) in their study (Land, Carlson or Killough). More oil was recovered, according to the Carlson two-phase hysteresis model with Stone 1 correlation. As a result, when compared to other models, it can be employed. According to sensitivity analysis, the largest amount of oil was recovered at a WAG ratio of 1:1. Due to the lowest miscibility pressure obtained, oil output increased with the shortest WAG cycle time at 180 days.

Swapnil et al., (2020), studied the optimization of WAG (CO2) flooding for enhanced oil recovery, through experimentation and simulation. They worked on the screening of injection of water- alternating-gas (WAG) to tap the residual oil saturation left in the reservoir by over and above the water flooding. Based on thermodynamic software, the minimum miscibility pressure of CO2 with crude oil was calculated and was discovered to be 1254 psi. For EOR during research, several WAG ratios of 1:1, 1.5:1, and 2:1 have been used. The efficiency of the WAG process has been investigated by simulation of water injection followed by CO2 injection. To achieve greater contact miscibility, a total of two WAG injection cycles with water flow rates of 1 ml/min and gas injection pressures of about 1250 psi were performed. Various cycles of the WAG process were used to create, assemble, and interpret the experimental data. Observations indicate that WAG ratio 2:1, which represents around 34% of the original oil in place, exhibits the largest incremental oil recovery. More oil is recovered when the WAG ratio rises.

By conducting an experiment, Madhav and Dandina, (2005) examined the performance of the miscible and immiscible Water Alternating Gas (WAG) process. In WAG injection technique, the gas is typically intermittently injected with water to expand the area of the reservoir that the injected gas contacts. In order to evaluate performance, oil recoveries from WAG injection and continuous gas injection (CGI) were compared. The main steps in the flood protocol were brine saturation, absolute permeability measurement, oil flooding (drainage) to initial oil saturation, end-point oil permeability measurement, brine flooding (imbibition) to residual oil saturation, end-point water permeability measurement, and finally tertiary gas injection (in both continuous injection and WAG modes) to recover the waterflood residual oil. The WAG method of injection outperformed the CGI when oil recovery per unit volume of gas injection was employed as a metric to assess the flooding.

To find the best injection fluid for the ultimate oil recovery and asphaltene precipitation experiments, a laboratory displacement investigation of four Water-Alternating-Gas (WAG) scenarios (CO2/water, N2/water, associated gas/water, and associated gas/hot water) was conducted by Yaser et al., (2015). The best ultimate recovery was for hot water alternating gas, which had a recovery rate of 88.5 percent after studies were conducted to determine the optimal way for recovering oil. Oil volume expansion and a decrease in oil viscosity are two advantages of WAG injection. The WAG method uses gas to displace the remaining oil that water flooding has immobilized, increasing the recovery process' microscopic displacement.

Thamudi et al., (2022) investigated the performance between water alternating gas and water huff and puff techniques in Jilin tight oil field. The effectiveness, recoveries, and economic considerations of the water alternating gas (WAG) and water huff-n-puff procedures for oil recovery in a tight oil reservoir were compared in the study. Additionally, the factors affecting the recovery based on both strategies were evaluated. A Software called ECLIPSE 300 was used to model, develop, and simulate the reservoir for the Jilin tight oil field. After 2922 days of simulation, the results revealed that WAG produced 30,453.271 Sm3 of the total field oil whereas the water huff-and-puff methodology produced 1,726.389 Sm3, demonstrating that WAG produces superior outcomes than employing a water huff-and-puff strategy. In addition, the WAG's best mode, which starts with water injection before switching to gas injection ($CO_2$) for one-year cycles on each, demonstrates an optimal oil recovery efficiency of 47.40 percent. Therefore, WAG is a preferential technique for the development of tight oil reservoirs.

The impact of water alternating gas injection on ultimate oil recovery was researched by Saikou, (2013). He looked at the enhancement of ultimate oil recovery when immiscible water alternating gas (WAG) injection is used as an enhanced recovery method under laboratory settings. Three WAG injection tests on three Wallace sandstone core plugs were performed in the lab using synthetic brine that replicated formation water from offshore Brazil. Each test was preceded by either a water or gas injection. Benchtop Relative Permeameter was used for the test runs. The experiment's findings reveal that using WAG injection after secondary water or gas injection can increase original oil recovery by up to 21%. (OOIP).

Vishnu et al., (2019), carried out an experimental study of Oil Recovery by Water-Alternating-Gas (WAG) process in Microporous media. In this investigation, experiments were carried out in a transparent, water-wet, microporous model that was first filled with crude oil and packed with glass beads. To define the dynamics of three-phase flows and its related oil recovery, alternate cycles of gas and water were injected. Using cutting-edge image processing techniques, the displacement of the leftover oil at the end of each WAG injection cycle was carefully examined. It was found that the repeated WAG injection cycles efficiently displaced the residual oil that remained inside the water-wet porous media after the initial water flooding by allowing the saturated residual oil to disperse over the porous region.

A review on enhanced oil recovery using water-alternating gas (WAG) injection was conducted by Shokufe et al. (2018), who came to the conclusion that WAG injection is a mature EOR technique with proven results in several projects from the pore to field size. For a typical oilfield, the average recovery factor is about 40%, meaning that despite the extensive production infrastructures, a sizable amount of oil is still left behind after primary oil recovery. Using four WAG injection techniques ($CO_2$/Water, $N_2$/Water, associated gas/Water, and associated gas/Hot water injections), they found that the $CO_2$ gas has a higher advantage over the $N_2$ or $O_2$ gases.

Lazreg and Syed, (2019) developed a semi-numerical model for WAG incremental recovery factor prediction based on data mining of published WAG pilots. An extensive review of published WAG pilot projects was carried out to provide a robust analytical predictive tool that can estimate WAG incremental factor, and consequently, 33 projects from 28 field around the world were selected for this research study. A total of 177 observations from the field WAG incremental recovery factor and parameters were fed into the predicted model. The created predictive model is capable of predicting the WAG incremental recovery factor in relation to a variety of input parameters, such as rock type, WAG process type, hydrocarbon pore volume of injected gas, reservoir permeability, oil gravity, oil viscosity, reservoir pressure, and reservoir temperature.

## III. METHODOLOGY

### Materials

In this research work, a computer software known as "ECLIPSE Compositional Simulator" was used to model and simulate the hydrocarbon flow of an oil field in the Niger Delta. This chapter discussed the use of this software in optimizing oil recovery using WAG method in comparison with water flooding and gas injection. Reliable production data from an oil field operating in the Niger Delta was obtained and the behavior of the field was analyzed.

Eclipse is a compositional software used for modelling and simulating multicomponent hydrocarbon flow in reservoirs or reservoir fluid flow in which there are compositional changes associated with depth,

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condensates or volatile crude oils, gas injection programs, and secondary recovery studies.

Methods

In this research work, a computer software known as "ECLIPSE Compositional Simulator" was used to model and simulate the hydrocarbon flow of an oil field in the Niger Delta. This chapter discussed the use of this software in optimizing oil recovery using WAG method in comparison with water flooding and gas injection.

Steps in Eclipse Simulation

Eclipse is a compositional software used for modelling and simulating multicomponent hydrocarbon flow in reservoirs or reservoir fluid flow in which there are compositional changes associated with depth, condensates or volatile crude oils, gas injection programs, and secondary recovery studies. The following are the steps followed in carrying out a simulation with ECLIPSE.

- Open the Eclipse Simulator, add a data sheet and run. This interface is shown in Fig.3.
- Click on the 'FloViz' and run, to open the simulation model.
- The simulation and modelling were first carried out for natural depletion.
- Optimization is done under WAG, waterflooding and gas injection.
- Optimal placement of injector wells was done based on the location of the residual oil.
- The injection wells were placed to efficiently sweep the residual oil to the production wells.
- Finally, open the 'Office' chart and run, to display the simulation plots and results.

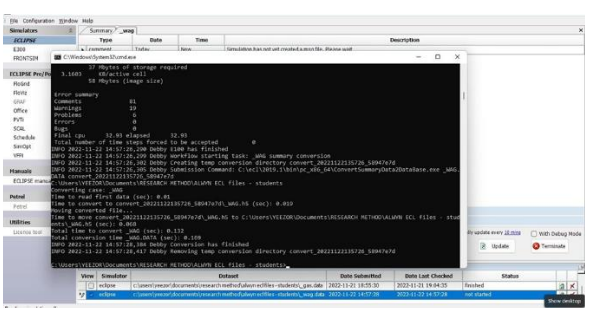

Fig. 3: Using Eclipse Simulator to run a datasheet. (Source: Eclipse Compositional Simulator)

Field Case Study

The case study field is an oil field located in the Niger Delta basin. Its original oil in place (OOIP) is estimated to be about 35.7MMSTB. The predicted dominant drive mechanism of the oil Field is the natural depletion (rock/fluid expansion), this is because the reservoir pressure was found to be initially above the bubble point pressure. Below the bubble point, the solution gas drive is expected to be dominant. The field data is shown in Table 1.

Table 1: Field Data

FIELD DATA

| | | |
|---|---|---|
| Original Oil in Place (OOIP) | 35,665,294 | STB |
| API Gravity | 39 | °API |
| Recovery Factor | 14.305 | % |
| Oil Formation Volume Factor (Bo) | 1.6629 | rbbl/STB |
| FVF at Initial Reservoir Pressure | 1.6024 | rbbl/STB |
| Oil Viscosity | 0.3942 | cP |
| Water Viscosity | 0.27 | cP |
| Rock Compressibility | $5.00 \times 10^{-5}$ | 1/psi |
| Water Compressibility | $5.00 \times 10^{-5}$ | 1/psi |
| Oil Saturation | 0.85 | Fraction |
| Initial Water Saturation | 0.39 | Fraction |
| Saturation Pressure | 300 | psi |
| Oil Density | 829.7675 | lb/ft³ |
| Gas Density | 1.0449 | lb/ft³ |
| Water Density | 1020 | lb/ft³ |

*(Source: From an oil field in Niger Delta)*

Reservoir Simulation under the Natural Depletion

This involves producing from a reservoir using its natural energy. This case will simulate reservoir recovery performance under natural depletion. The initial 4 producer wells (A2, A4,N1, N3) were simulated as shown in Fig.4. To ensure the validity of ECLIPSE simulator, the reservoir performance is investigated without optimization, to determine the field oil efficiency (FOE), the field oil production rate (FOPR) and the field oil production total (FOPT), in comparison with the initial field data. Table 2 shows the well specifications for natural depletion simulation.

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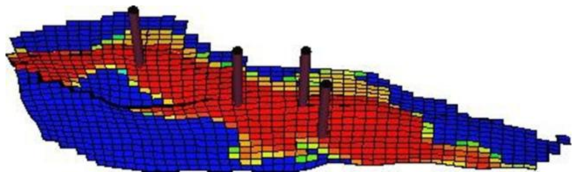

Fig. 4: A 3D Model of Natural Depletion (Source: Simulation Model)

Table 2: Well specifications for the Natural Depletion

| Well | Group | I | J | Depth | Phase | 3* | Crossflow |
|---|---|---|---|---|---|---|---|
| N2 | G1 | 11 | 26 | 1* | OIL | 3* | NO |
| N3 | G1 | 20 | 13 | 1* | OIL | 3* | NO |
| A2 | G1 | 6 | 28 | 1* | OIL | 3* | NO |
| A4 | G1 | 12 | 21 | 1* | OIL | 3* | NO |

Reservoir Simulation for Waterflooding

To investigate the reservoir performance using water injection recovery method, a reservoir simulation model was developed. The petrophysical properties (porosity, permeabilities and NTG) are included in the grid in the file:'MODEL PETREL PETRO. GRDECL'. Most of the data are already written in the Eclipse data file.

In this case, 6 producer wells namely N2, N3, A4, E2, E3 & E4 and 4 injector wells (INJ1, INJ2, INJ3 & INJ4) were used for reservoir pressure maintenance as shown in Fig.5. From FLOVIZ the perforations of the wells 'A4' and 'N3' was adjusted to ensure that it produces from the oil- bearing zones only. Table 3 shows the well specifications for water injection simulation.

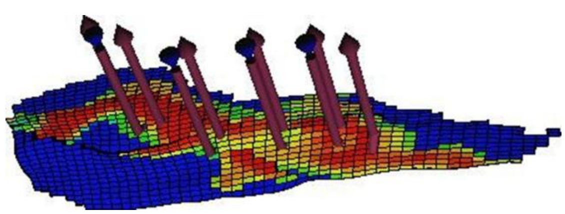

Fig.5: A 3D Model of Waterflooding (Source: Simulation Model)

Table 3: Well specifications for Waterflooding

| Well | Group | I | J | Depth | Phase | 3* | Crossflow |
|---|---|---|---|---|---|---|---|
| N2 | G1 | 11 | 26 | 1* | OIL | 3* | NO / |
| N3 | G1 | 20 | 13 | 1* | OIL | 3* | NO / |
| --'A2' | 'G1' | 6 | 28 | 1* | 'OIL' | 3* | NO / |
| A4 | G1 | 12 | 21 | 1* | OIL | 3* | NO / |
| E2 | G1 | 5 | 31 | 1* | OIL | 3* | NO / |
| E3 | G1 | 16 | 17 | 1* | OIL | 3* | NO / |
| E4 | G1 | 8 | 38 | 1* | OIL | 3* | NO / |
| INJ1 | G2 | 9 | 20 | 1* | WATER | 3* | NO / |
| INJ2 | G2 | 16 | 14 | 1* | WATER | 3* | NO / |
| INJ3 | G2 | 7 | 31 | 1* | WATER | 3* | NO / |
| INJ4 | G2 | 8 | 26 | 1* | WATER | 3* | NO / |

(Source: From an oil field in Niger Delta)

Reservoir Simulation for Gas Injection

In this scenario, gas injection was simulated to determine its recovery performance. In Eclipse, 'FLOVIZ' was used to model gas injection as shown in Fig. 6. The four injector wells were used to simulate the gas injection to ascertain the field oil efficiency. The objective is to achieve the longest production time possible with the minimum number of injection wells. The well specifications for gas injection simulation are shown in Table 4.

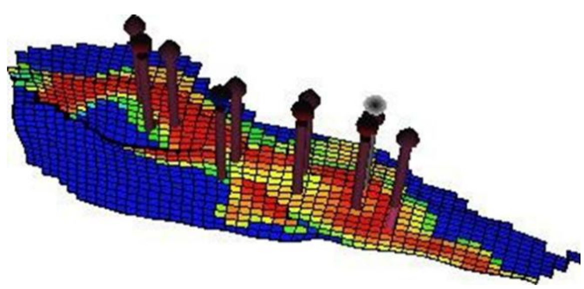

Fig.6: A 3D Model of Gas Injection (Source: From Simulation Model)

Table 4: Well specifications for Gas Injection

| WELL | GROUP | I | J | DEPTH | PHASE | 3* | Crossflow |
|---|---|---|---|---|---|---|---|
| N2 | G1 | 11 | 26 | 1* | OIL | 3* | NO / |
| N3 | G1 | 20 | 13 | 1* | OIL | 3* | NO / |

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| WELL | GROUP | I | J | DEPTH | PHASE | 3* | Crossflow |
|---|---|---|---|---|---|---|---|
| --A2 | G1 | 6 | 28 | 1* | OIL | 3* | NO / |
| A4 | G1 | 12 | 21 | 1* | OIL | 3* | NO / |
| E2 | G1 | 5 | 31 | 1* | OIL | 3* | NO / |
| E3 | G1 | 16 | 17 | 1* | OIL | 3* | NO / |
| E4 | G1 | 8 | 38 | 1* | OIL | 3* | NO / |
| INJ1 | G2 | 9 | 20 | 1* | GAS | 3* | NO / |
| INJ2 | G2 | 16 | 14 | 1* | GAS | 3* | NO / |
| INJ3 | G2 | 7 | 31 | 1* | GAS | 3* | NO / |
| INJ4 | G2 | 8 | 26 | 1* | GAS | 3* | NO / |

(Source: From an oil field in Niger Delta)

Reservoir Simulation for WAG Injection

In this case, there was an introduction of gas injection into the reservoir using the already drilled injection wells initially used to inject water. The water alternating gas (WAG) scheme was introduced, where gas is injected alternatively with water. The simulation model for WAG injection is displayed in Fig.7. Table 5 shows the well specifications for WAG injection simulation.

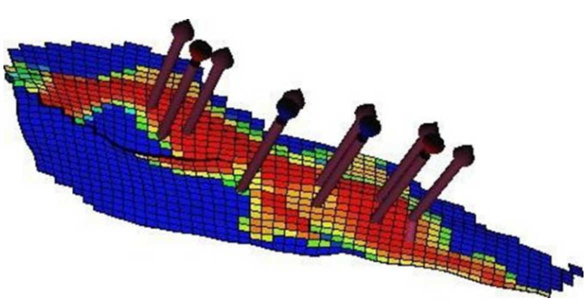

Fig.7: A 3D Model of WAG Injection (Source: From Simulation Model)

Table 5: Well specifications for WAG Injection

| WELL | GROUP | I | J | DEPTH | PHASE | 3* | Crossflow |
|---|---|---|---|---|---|---|---|
| N2 | G1 | 11 | 26 | 1* | OIL | 3* | NO / |
| N3 | G1 | 20 | 13 | 1* | OIL | 3* | NO / |
| --A2 | G1 | 6 | 28 | 1* | OIL | 3* | NO / |
| A4 | G1 | 12 | 21 | 1* | OIL | 3* | NO / |
| E2 | G1 | 5 | 31 | 1* | OIL | 3* | NO / |
| E3 | G1 | 16 | 17 | 1* | OIL | 3* | NO / |
| E4 | G1 | 8 | 38 | 1* | OIL | 3* | NO / |
| INJ1 | G2 | 9 | 20 | 1* | WATER | 3* | NO / |
| INJ2 | G2 | 16 | 14 | 1* | GAS | 3* | NO / |
| INJ3 | G2 | 7 | 31 | 1* | GAS | 3* | NO / |
| INJ4 | G2 | 8 | 26 | 1* | WATER | 3* | NO / |

(Source: From an oil field in Niger Delta)

## IV. RESULTS FROM NATURAL DEPLETION SIMULATION

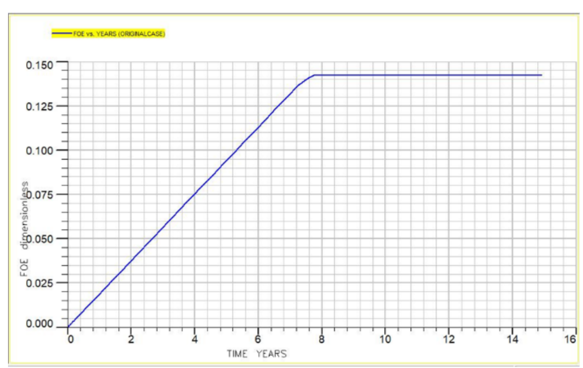


Fig. 8: Plot of FOE vs TIME (yrs) –Natural Depletion

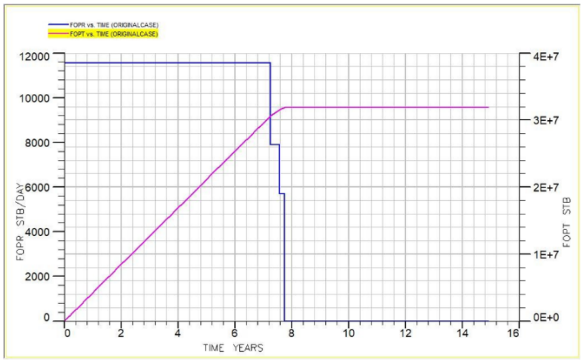


Fig. 9: Plot of FOPR & FOPT vs TIME (yrs) – Natural Depletion

## V. DISCUSSION OF NATURAL DEPLETION RESULT

Table 6: Natural Depletion Results

| FOE (%) | FOPR (STB/Day) | FOPT (MMSTB) | Plateau (yrs) | Total Production Time (yrs) |
|---|---|---|---|---|
| 0.1427 | 11,571 | 32 | 7.2 | 7.7 |

The 'office' chart in ECLIPSE showed the results of the natural depletion simulation. From Table 6, the results show that the reservoir performance under natural depletion has a maximum field oil efficiency (recovery factor) of 14.27%, which is close to the initial recovery factor of 14.305% from the oil field data, therefore, the validity of the software is said to have been ascertained. Additionally, at a field oil production rate (FOPR) of 11,571stb/day, a plateau of 7 years and 2 months was maintained. The total oil production time was 7 years and 7 months, at a total oil field production (FOPT) of 32 MMSTB.

From Fig. 8, it is observed that the field oil efficiency (recovery factor) gradually increases until the 7.7 year when it remained constant at 14.27%. However, analysis from Fig. 9, shows that the rate of oil production (FOPR) was stable or remained constant at 11,571STB/Day until the 7.2yr where there was a sudden decline. This decline continued until the 7.7 year. The field oil efficiency (recovery factor) and the total oil production increased gradually until the 7.7 year where the total oil production remained constant at 32 MMSTB. However, the recovery factor continues to increase to 14.27% and remained constant from the 7.7 yr.

## VI. RESULTS FROM WATERFLOODING SIMULATION

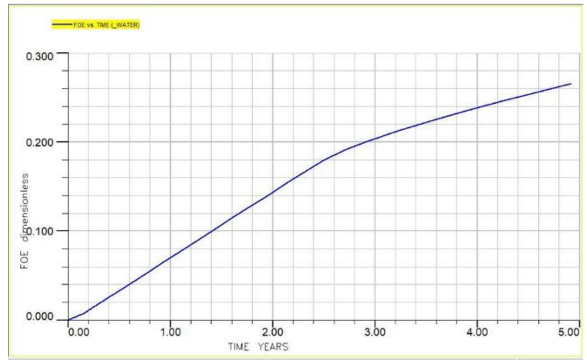


Fig. 10: Plot of FOE (Recovery Factor) vs TIME (yrs) – Waterflooding

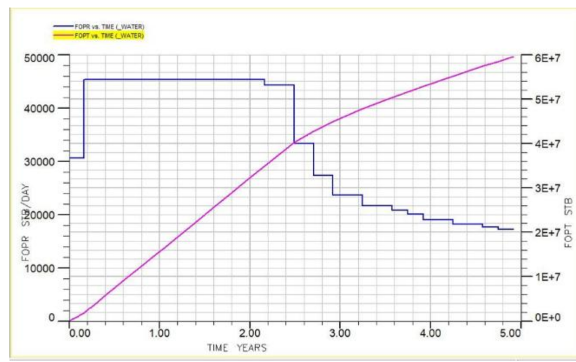


Fig. 11: Plot of FOPR & FOPT vs TIME (yrs) – Waterflooding

## VII. DISCUSSION OF WATERFLOODING RESULT

Table 7: Waterflooding Results

| FOE (%) | FOPR (STB/Day) | FOPT (MMSTB) | Plateau (yrs) | Total Production Time (yrs) |
|---|---|---|---|---|
| 0.266545474 | | 59.62 | 2.2 | 4.9 |

From Table 7, the results show that the reservoir performance with waterflooding has a maximum recovery factor of 26.65%. Also, at a field oil production rate (FOPR) of 45474stb/day, a plateau of 2 years and 2 months was maintained. The total oil

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production time was 4 years and 9 months, at a total oil field production (FOPT) of 59.62 MMSTB. According to the analysis from Fig. 10, the field oil efficiency (recovery factor) gradually rises until the 2.5-year mark, at which point there is a little decline. It kept rising steadily until it reached its highest point at 26.25 percent. Additionally, study of Fig. 11 reveals that the rate of oil production (FOPR) is first constant for a short period before increasing quickly to 45474 STB/Day and is maintained for 2.2 years, following which it gradually declines till 4.9 years. The total oil production increased gradually up till 59.62 MMSTB.

## VIII. RESULTS FROM GAS INJECTION SIMULATION

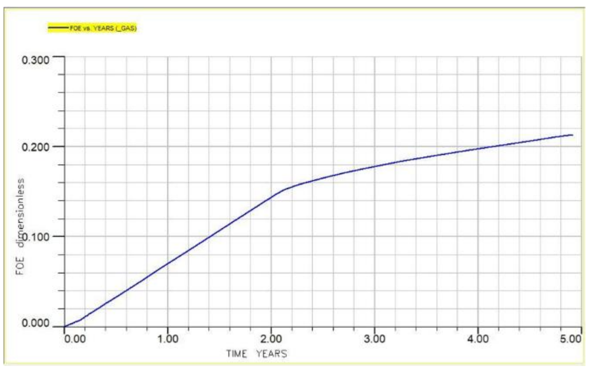


Fig. 12: Plot of FOE (Recovery Factor) vs TIME (yrs) – Gas Injection

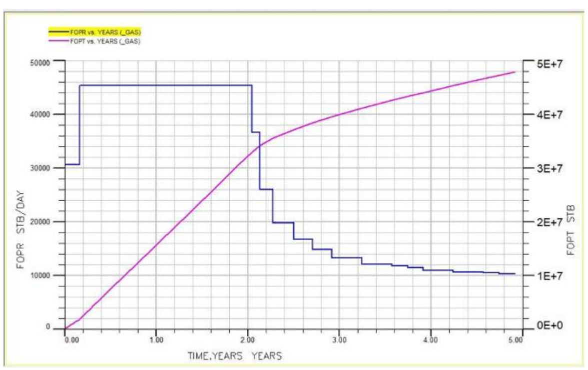


Fig.13: Plot of FOPR & FOPT vs TIME (yrs) – Gas Injection

## IX. DISCUSSION OF GAS INJECTION RESULT

Table 8: Gas Injection Results

| FOE (%) | FOPR (STB/Day) | FOPT (MMSTB) | Plateau (yrs) | Total Production Time (yrs) |
|---|---|---|---|---|
| 0.2135 | 45474 | 47.89 | 2.0 | 4.9 |

According to Table 8, there is a maximum recovery factor of 21.35 percent for reservoir performance with gas injection. A 2-year plateau was also maintained at a field oil production rate (FOPR) of 45474 STB/day. The FOPR was found to be consistent with the results of the water flooding, but for the gas injection, the constant production rate only persisted for a shorter period of time. The total oil field production (FOPT) was 47.89 MMSTB during a period of 4 years, 9 months.

The field oil efficiency (recovery factor) continuously increases until the 2.1-year milestone, at which time there is a slight reduction, according to the analysis from Fig. 12. It continued to increase steadily until it topped out at 21.35 percent. Furthermore, analysis of Fig. 13 shows that the rate of oil production (FOPR) first remains constant for a brief period before rising swiftly to 45474 STB/Day and was constant for 2.1 years, after which it steadily decreases till 4.9 years. The total oil production increased gradually up till 47.89 MMSTB.

## X. RESULTS FROM WAG INJECTION SIMULATION

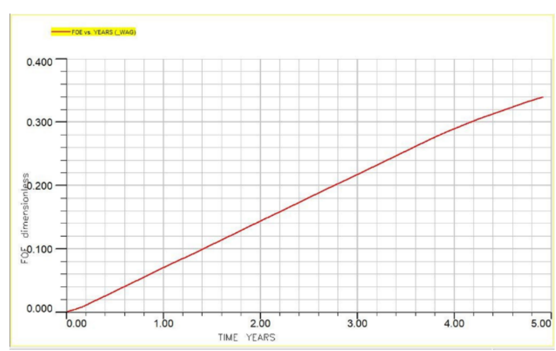


Fig. 14: Plot of FOE vs TIME (yrs) – WAG Injection

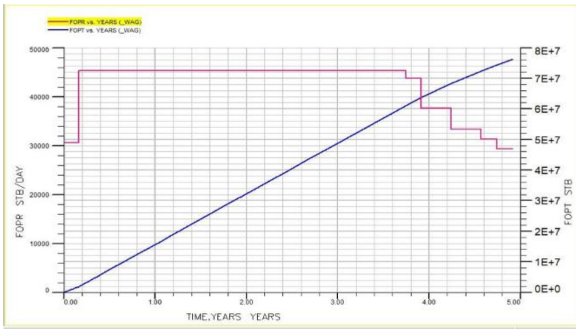


Fig. 15: Plot of FOPR & FOPT vs TIME (yrs) – WAG Injection

## XI. DISCUSSION OF WAG INJECTION RESULT

Table 9: WAG Injection Results

| FOE (%) | FOPR (STB/Day) | FOPT (MMSTB) | Plateau (yrs) | Total Time (yrs) | Production |
|---|---|---|---|---|---|
| 0.34 | 45474 | 76.46 | 3.7 | 4.9 | |

From Table 9, the results show that the reservoir performance with WAG injection has a maximum recovery factor of 34%. Also, at a field oil production rate (FOPR) of 45474stb/day, a plateau of 3 years and 7 months was maintained. The FOPR remained consistent with that of waterflooding and gas injection results, however for the WAG injection the constant production rate lasted for a longer period. The total oil production time was 4 years and 9 months, at a total oil field production (FOPT) of 76.46 MMSTB.

The analysis from Fig. 14 show that the field oil efficiency (recovery factor) gradually rises until it reached its highest point at 34 percent. Additionally, study of Fig. 15 reveals that the rate of oil production (FOPR) is first constant for a short period before increasing quickly to 45474 STB/Day and was constant for 3.7 years, following which it gradually declines till 4.9 years. The total oil production increased gradually up till 76.46 MMSTB.

## XII. COMPARING WATERFLOODING, GAS AND WAG INJECTION

FOE Comparative Analysis

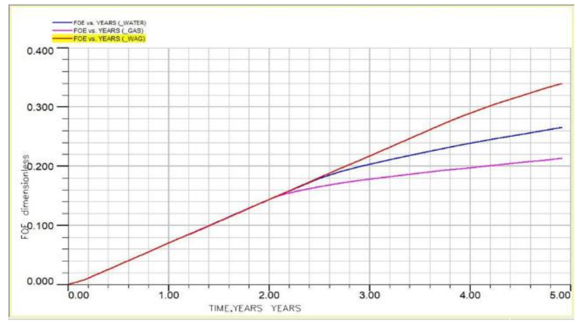


Fig.16: Plot of FOE vs TIME (yrs) – Waterflooding, Gas and WAG Injection

Table 10: FOE Results for Waterflooding, Gas and WAG Injection

| FOE [ Recovery Factor] (%) | | |
|---|---|---|
| Waterflooding | Gas Injection | WAG Injection |
| 0.2665 | 0.2135 | 0.34 |

Analysis from Fig. 16 the field oil efficiency (recovery factor) for gas injection continuously increases along with that of waterflooding and WAG, until the 2.1-year, at which point it reduces steadily until it topped out at 21.35 percent. While for that waterflooding the FOE continued rising until the 2.5-year mark, where it started to decline steadily until it reached its highest point at 26.25 percent. The FOE for WAG injection maintained its steady increase to the highest point of 34 percent.

From Table 10, it can be seen that WAG injection has a better performance than gas injection and waterflooding with the highest maximum field oil efficiency of 34%, followed by waterflooding with 26.65% and the least is gas injection with 21.35%.

FOPR Comparative Analysis

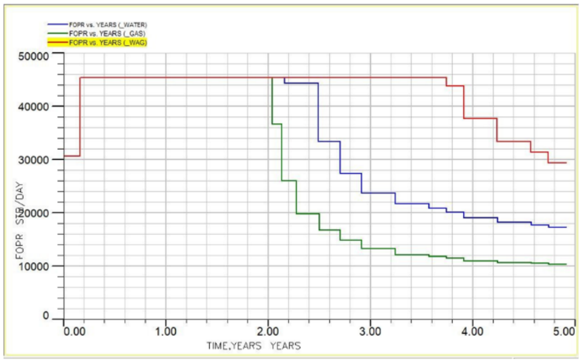


Fig.17: Plot of FOPR vs TIME (yrs) – Waterflooding, Gas and WAG Injection

Table. 11: FOPR (Plateau) Results for Waterflooding, Gas and WAG Injection

| FOPR [Plateau] (yrs) | | |
|---|---|---|
| Waterflooding | Gas Injection | WAG Injection |
| 2.2 | 2.0 | 3.7 |

Analysis from Fig. 17 and Table 11, shows that the field production rate WAG injection has the longest plateau of 3 years and 7 months, while gas injection production rate lasted for just2 years. The production rate of waterflooding lasted for 2 years and 2 months.

FOPT Comparative Analysis

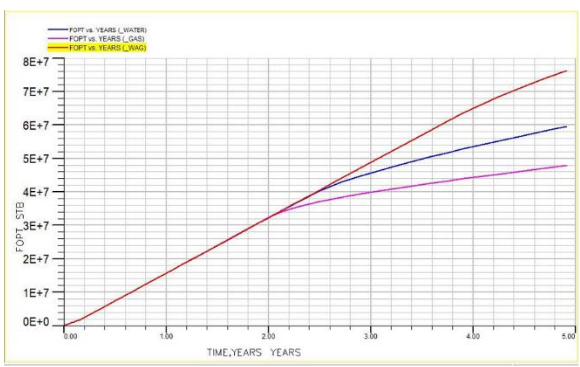


Fig.18: Plot of FOPT vs TIME (yrs) – Waterflooding, Gas and WAG Injection

Table 12: FOPT Results for Waterflooding, Gas and WAG Injection

| FOPT (MMSTB) | | |
|---|---|---|
| Waterflooding | Gas Injection | WAG Injection |
| 59.62 | 47.89 | 76.46 |

From Fig. 18 and Table 12, WAG injection had a total oil field production (FOPT) of 76.46 MMSTB, which was the highest, followed by waterflooding with 59.62 MMSTB. And gas injection had the least total field production of 47.89 MMSTB.

FWCT Comparative Analysis

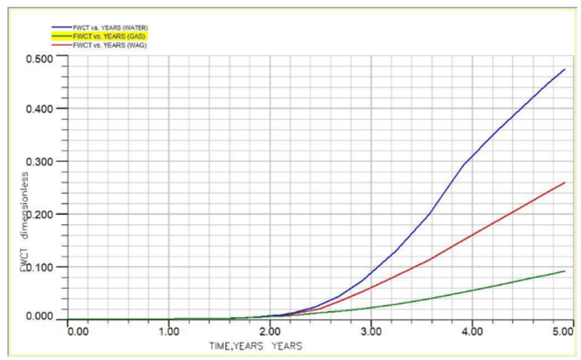


Fig.19: Plot of FWCT vs TIME (yrs) – Waterflooding, Gas and WAG Injections

Table. 13: FWCT Results for Waterflooding, Gas and WAG Injection

| FWCT (%) | | |
|---|---|---|
| Waterflooding | Gas Injection | WAG Injection |
| 0.4758 | 0.092 | 0.2611 |

From Fig. 19 and Table 13, it was observed that the water cut for gas injection was very minimal with 9.2%, while waterflooding technique has the highest water cut of 47.58%. This means for waterflooding, there will be early breakthrough and more water would be produced. WAG injection had its water cut as 26.11%, indicating that considerable amount of oil can be produced before the water breakthrough.

## CONCLUSION

WAG injection is a tertiary oil recovery technique whose application and acceptance are widely increasing in the oil and gas industry due to its proven and successful oil recovery performance. Hence, the purpose of this study was to determine the viability of WAG injection method for oil recovery for a selected field in the Niger Delta. The following key conclusions were drawn from this study:

- WAG injection had a maximum field oil efficiency (FOE) of 34%, a field oil production total (FOPT) of 76.46 MMSTB, a plateau time of 3.7years and a field water cut (FWCT) of 26.11%.
- Waterflooding had a FOE of 26.65%, a FOPT of 59.62 MMSTB, a plateau time of 2.2years and FWCT of 47.58%. Whereas gas injection had an FOE of 21.35%, a FOPT of 47.89 MMSTB, a plateau time of 2 years, and FWCT of 9.2%. From comparative analysis of the three recovery methods, WAG injection outperformed both waterflooding and gas injection with the highest FOE of 34%, the longest plateau time of 3.7years, and a minimal water cut of 26.11%.
- Therefore, WAG recovery method has thus far demonstrated to be the most effective recovery method, in comparison to waterflooding and gas injection methods.

## RECOMMENDATIONS

1. Further research on the economic analysis should be done because, in addition to having an excellent recovery performance, the cost of executing WAG may be a constraint on the recovery technique.

## CONTRIBUTION TO KNOWLEDGE

Field is currently under water flooding which contributed to the high water cut and high cost of production. The findings of this study will enable Engineers to improve decision making, reduce water cut, and extend well life resulting in cost savings and enhanced oil recovery.

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