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The Application of Water Alternating Gas Injection to Maximize Oil Recovery in the Niger Delta

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Authors' contributions

This work was carried out in collaboration among all authors. All authors read and approved the final manuscript.

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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 determine the viability of Water Alternating Gas (WAG) injection in comparison with Waterflooding and Gas injection methods for optimum oil recovery of an oil field in Niger Delta. WAG injection had a maximum field oil efficiency (FOE) of 31%, a field oil production total (FOPT) of 4,944 MMSTB, a plateau time of 14 years and a total field water

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production (FWPT) of 18,356 MMSTB. Waterflooding had a FOE of 23%, a FOPT of 37,466 MMSTB, a plateau time of 9 years and a FWPT of 96,895 MMSTB. Whereas gas injection had an FOE of 15%, a FOPT of 36,063 MMSTB, a plateau time of 3.2 years, and a FWPT of 13,444 MMSTB, respectively. From the comparative analysis of the three recovery methods, WAG injection outperformed both waterflooding and gas injection with the highest FOE of 31% and the longest plateau time of 14 years, respectively.

Keywords: Water alternating gas; waterflooding; gas injection; oil recovery.

1. INTRODUCTION

High water cut has been one of the most significant challenges for extending production life in mature waterflood fields Couple with high reservoir heterogeneity, extensive layering and faulting, these fields often developed irregular flood patterns after decades of production which compounded the challenge to optimizing recovery from these fields. The severity of this problem can be seen in the Niger Delta oil fields where there are several matured fields that are producing at high water cut after many years of water flooding.

X field is situated offshore Nigeria, in water depths of about 60 meters and within 60 kilometers off the Nigerian South-eastern coast. The field was initially developed in 2000 and has been in production since then. At the beginning of production, the field produced at a rate of 27 kbopd with 4 oil wells and no water injection. Additional two production wells and three water injection wells were drilled after 10 years of production, Daily Well and Reservoir Management became very challenging due to the operational dynamics, which were based on the pressure maintenance by water injection to sustain daily oil production. Thus, the Well and Reservoir Management plan focused on sustained and efficient water-injection throughout the field life to optimize oil production alongside good reserves development.

Three different fluid types are present in the shallow marine sandstone reservoir crude. The depth of the reservoir varies between 2000m and 4900m sub-surface, and the temperature is about 150 ºC. The wells typically have a measured length above 4000m, resulting in a noticeable pressure drop along the production path. The majority of the producing wells are producing with relatively low oil rates (below 1000 stb/d) and high-water cuts.

1.1 Geological Background

According to Anonymous [1], the X field structure is composed of combined stratigraphic and structural traps as highlighted below in Fig. 1. The term 'X' is a fictitious name chosen to protect the identity of the field. The reservoir series are Lower Pliocene in age (Qua Iboe formation) and consist of turbidite sands. The hydrocarbon column height is greater than 400m. The field reservoir is highly compartmentalized and therefore very complex. The reservoir varies in thickness and is located in a stratigraphic pinch-out structure.

In the Gulf of Guinea in West Africa, the Niger Delta lies between latitudes 4° and 7°N and longitudes 3° and 9°E [3].

According to Doust and Omatsola [4], depobelts in the Niger Delta were formed as a result of active deposition in a portion of the delta, which was facilitated by large-scale withdrawal and seaward movement of the basal under compacted and geo-pressured marine Akata shales under the weight of the advancing paralic Qua Iboe clastic wedge. With respect to defining a working petroleum system for the Niger Delta, the Akata shales constitute the source from which hydrocarbon generation and expulsion occurred. Fractures and faults served as migration paths into reservoir rocks within the Qua Iboe formation. The field fluid is saturated oil of 39°API with low viscosity of 0.3942 cP and has been divided to producers and injectors in six segments: Crest, Downdip, C-sand, Southwest, South-South and South-East.

Bruso et al. [2] classified reservoir deposition into three major components along the southeastern Niger Delta/Equitorial Guinea axis. The authors explained that in the northerly updip section of the axis (Nigeria), shallow water delta-front sandstone deposition predominated along extensional deltaic growth faults that formed near the active margin shelf. Fig. 2 provides a stratigraphic diagram of depositional features along the axis.

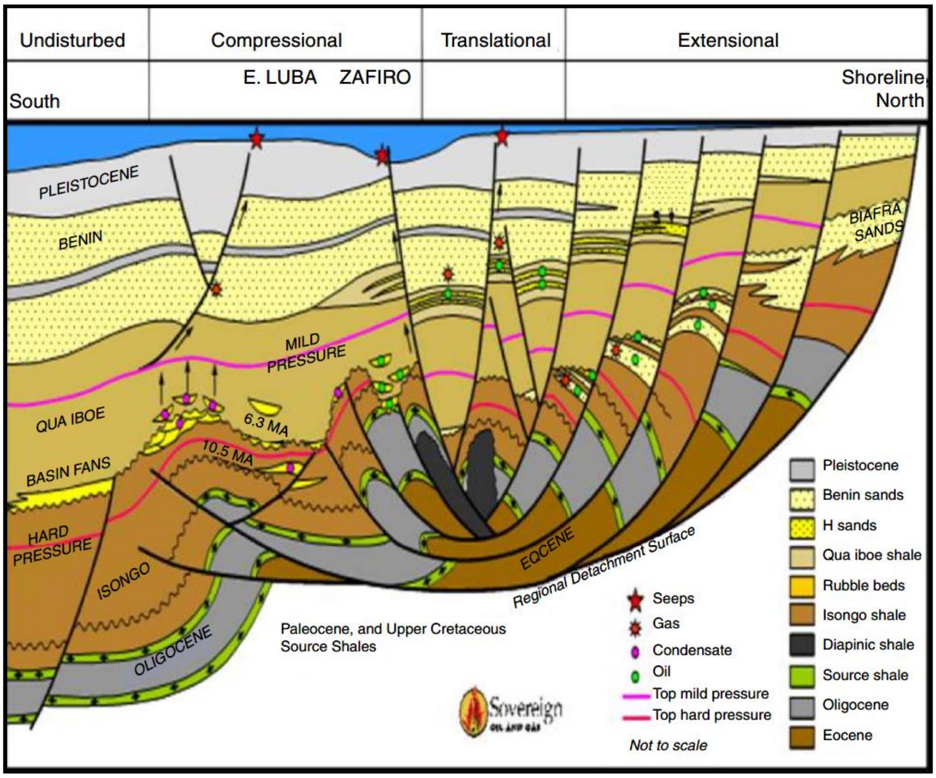

Fig. 1. Structural style in the equatorial Guinea-Nigeria, niger delta axis modified after Bruso et al. [2])

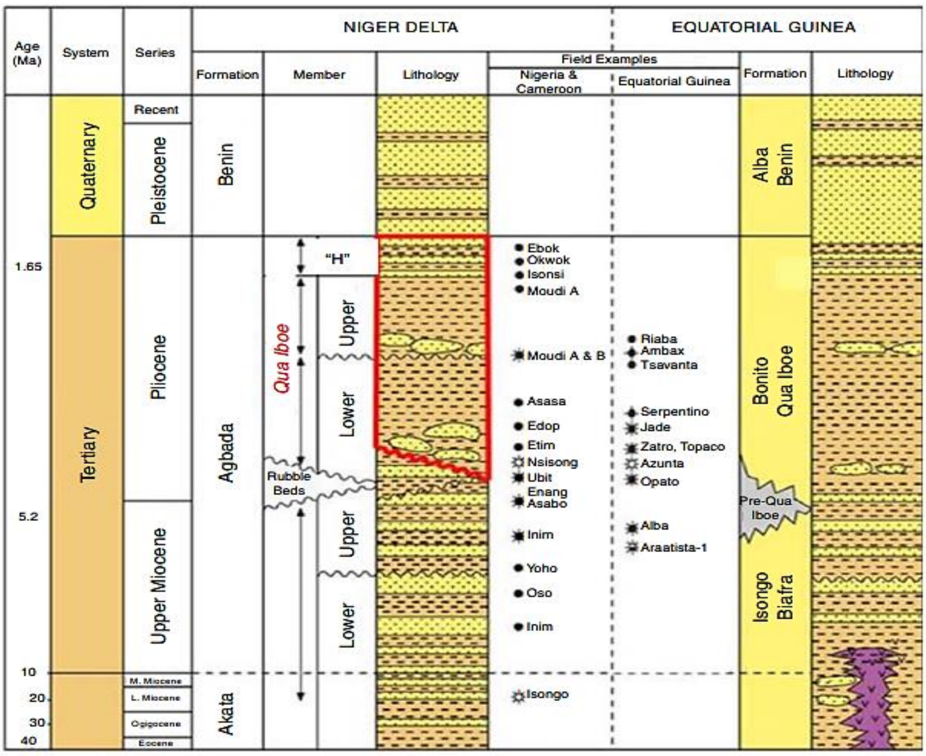

Fig. 2. Stratigraphic arrangement of deposition in southeastern Niger Delta, Nigeria, and its correlative equivalent in equatorial Guinea (modified after Bruso et al. [2])

In middip areas, slope shale and channel sand deposition predominated in the middle portion of the compartment, while it translated basinward along its over pressured basal-detachment surface. The X Field shares the features in the updip and middip outlined in Bruso et al. [2] Southerly downdip end of the axis is characterized by an imbricate series of compressional toe-thrust anticlines in mega-thrust sheets developed beneath the lower continental slope and rise [2].

1.2 Tertiary Oil Recovery

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 [5].

The recovery of crude oil can be grouped into three main categories:

- 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 [6].

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 [7].

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 [8].

A typical tertiary oil recovery technology, known as the Water Alternating Gas Injection process (WAG), is used to increase the displacement efficiency of the remaining oil that cannot be recovered during primary and secondary recovery procedures [9]. 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 WAG injection field projects in the United States of America (USA) 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 [10].

Water-alternating-gas (WAG) injection is widely used to further improve the recovery for oilfields, on top of secondary recovery methods e.g. water or gas injection. During WAG injection, water and gas will be injected in alternating sequence i.e. water is injected at predetermined rate for certain duration, followed by gas injection, and continuously alternating between water and gas periodic injection until the target oil recovery is achieved [11]. Andriushchenko et al. [12] describes the optimization (NPV maximization) of East Siberian Yaraktinskoe field immiscible WAG project after 5 years of its successful operation. The project execution has revealed operational issues with lack of gas injection after water injection in 6 wells and gas breakthroughs with decrease of liquid/oil rates by 40% in 6 wells.

Arne et al. [13], demonstrated advanced near miscible WAG modelling including WAG three-phase hysteresis, and present cases of Foam Assisted WAG (FAWAG) revisited with several novel modelling approaches. Zhizeng et al. [14]. Evaluated the effectiveness of water alternating CO2 (CO2-WAG) flooding in ultra-low permeability reservoir block Z, oil samples from a typical well were used to carry out laboratory experiments, including oil composition analysis, constant composition expansion and CO2 swelling test. The results showed that: (1) CO2-WAG flooding could maintain a longtime stable production with high oil rate, and significantly improve the production effect of the ultra-low permeability reservoir. M. Mohamed et al. [15] estimated the impact of each factor (CO2 WAG) on elastic property and investigated a dominant factor through a rock physics study at a CO2 WAG site in Abu Dhabi.

Lekun et al. [16] conducted experimental research to investigate the CO2 displacement process in both homogeneous and heterogeneous cores. Furthermore, they validated the correlation between the timing of WAG injection and the heterogeneity of the cores. They concluded that the degree of heterogeneity increases, initiating WAG injection earlier leads to a more significant suppression of gas channeling, increased water–gas interaction, improved gas–oil contact, and enhanced the synergistic effect of increasing the resistance and pressure of WAG flooding and controlling gas channeling.

In this study, the Water-Alternating-Gas Injection (WAG) recovery method is used to determine the recovery performance of an oil reservoir in the Niger Delta in comparison to waterflooding and gas injection recovery method. To achieve this, the following objectives will be considered: 1. determine the recovery efficiency of WAG injection for an oil field in Niger Delta by using INTERSECT compositional simulator to model and simulate the flow performance, 2. assess incremental oil recovery by the use of WAG and 3. valuate whether WAG reduces water production.

2. METHODOLOGY

In this research work, the Schlumberger software known as “INTERSECT Compositional Simulator” was used to model and simulate the hydrocarbon flow of an oil field in the Niger Delta. The data used in this project was obtained from an oilfield operating in the Niger Delta. This chapter discussed the use of this software in optimizing oil recovery using the WAG method in comparison with water flooding and gas injection, respectively.

The INTERSECT high-resolution reservoir simulator addresses many reservoir challenges. By combining physics and performance in a fit-for-purpose reservoir simulator for reservoir models, the Intersect simulator enables high-resolution modeling. Reservoir engineers are provided with results that can be trusted to provide insight into understanding the progression of hydrocarbon in the reservoir at a resolution that is otherwise too costly to simulate. The outcome is improved accuracy and efficiency in field development planning and reservoir management, even for the most complex fields. It 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 involved in carrying out a simulation with INTERSECT.

- Open the INTERSECT Simulation Launcher and import a dataset. This interface is shown in Fig. 3.
- Click on the Migrator to convert the imported dataset into AFI. File and run the simulation.
- To run the Migrator, we used the following command: “eclrun ecl2ix basename” where basename is the root name of the input dataset. This command generates the AFI file but does not run INTERSECT on it.
- To find details of the command line options used by the Migrator, use the following command: eclrun exeargs="- h" ecl2ix basename.
- 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.

2.1 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 natural depletion (rock/fluid expansion), the reservoir pressure was initially found to be 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.

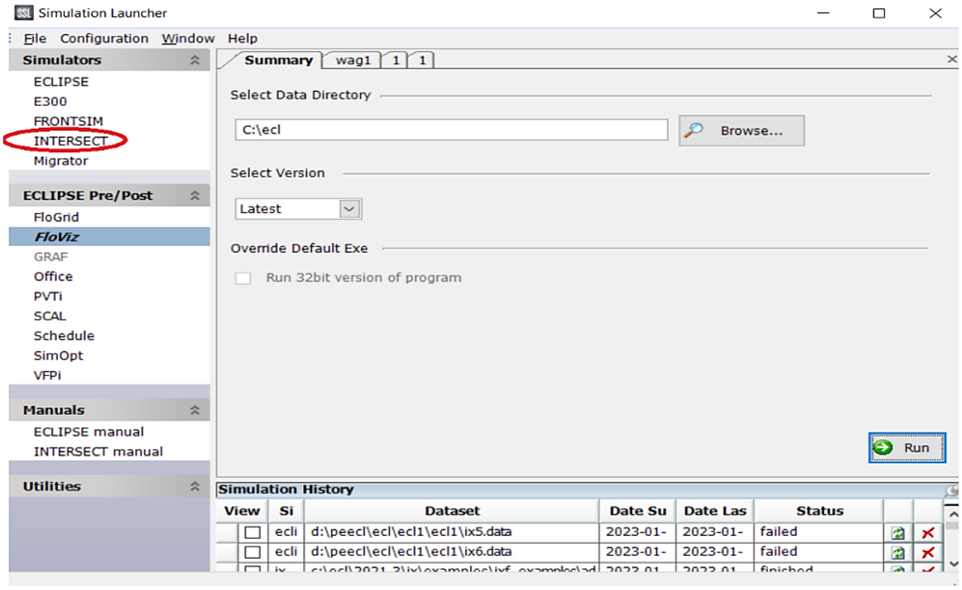

Fig. 3. Using INTERSECT simulator to run a datasheet.

Table 1. Field data

S/N	Field data	
1	Original Oil in Place [OOIP] (STB)	95,665,294
2	API	39
3	Recovery Factor (%)	14.305
4	Oil Formation Volume Factor (Bo)	1.6629
5	FVF Initial Reservoir Pressure (Rbbl/stb)	1.6024
6	Oil Viscosity (cp)	0.3942
7	Water Viscosity (cp)	0.27
8	Rock Compressibility (1/Psi)	$5.00 * 10^{-5}$
9	Water Compressibility (1/Psi)	$5.00 * 10^{-5}$
10	Oil Saturation (%)	0.85
11	Initial Water Saturation (%)	0.39
12	Saturation Pressure (Psi)	300
13	Oil Density (Ib/ft^3)	829.7675
14	Gas Density (Ib/ft^3)	1.0449
15	Water Density (Ib/ft^3)	1020

2.2 Reservoir Simulation under the Natural Depletion

This involves producing from a reservoir using its natural energy. In this case, reservoir recovery performance is simulated under natural depletion. The initial 4 producer wells (PROD1, PROD2, PROD3, and PROD4) were simulated as shown in Fig. 4. To ensure the validity of INTERSECT 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.

2.3 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 INTERSECT data file.

In this case, 6 producer wells namely PROD1, PROD2, PROD3, PROD4, PROD5 and PROD6, and 4 injector wells INJ1, INJ2, INJ3 and INJ4 were used for reservoir pressure maintenance, as shown in Fig. 5. Perforations of wells PROD5 and PROD6 were adjusted using FLOVIZ to ensure production from the oil-bearing zones only. Table 3 shows the well specifications for water injection simulation.

2.4 Reservoir Simulation for Gas Injection

In this scenario, gas injection was simulated to determine its recovery performance. 'FLOVIZ' in INTERSECT 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.

2.5 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.

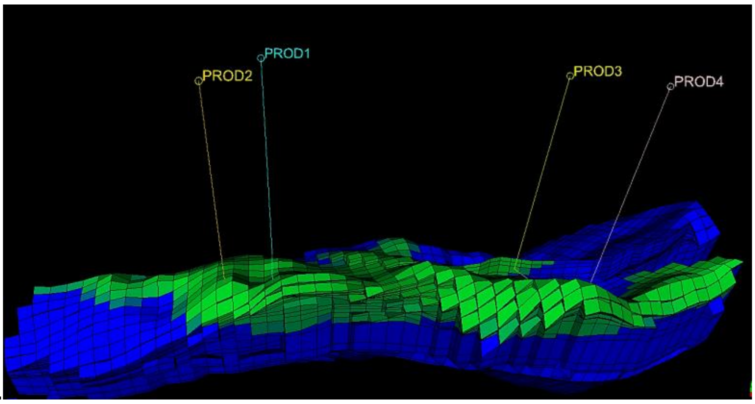

Fig. 4. A 3D model of natural depletion

Table 2. Well specifications for the natural depletion

Well	Group	I	J	Depth	Phase	3*	Crossflow
'PROD1'	'G1'	11	26	1*	'OIL'	3*	NO /
'PROD2'	'G1'	20	13	1*	'OIL'	3*	NO /
'PROD3'	'G1'	6	28	1*	'OIL'	3*	NO /
'PROD4'	'G1'	12	21	1*	'OIL'	3*	NO /

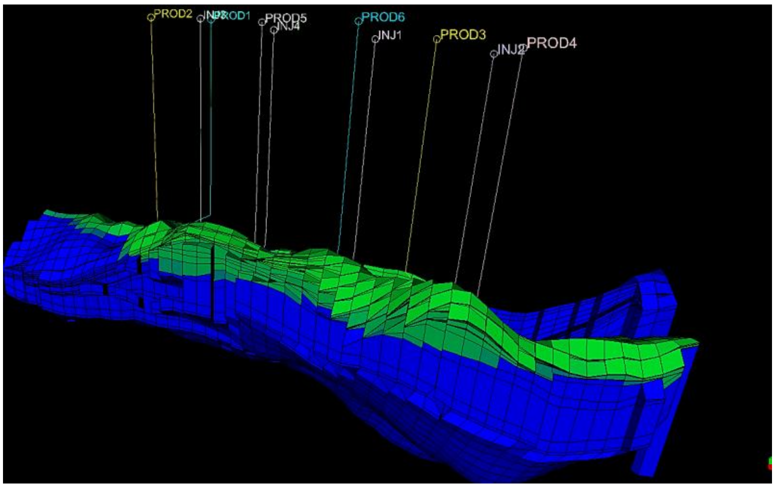

Fig. 5. 3D model of waterflooding

Table 3. Well specifications for waterflooding

Well	Group	I	J	Depth	Phase	3*	Crossflow
'PROD1'	'G1'	11	26	1*	'OIL'	3*	NO /
'PROD2'	'G1'	20	13	1*	'OIL'	3*	NO /
'PROD3'	'G1'	12	21	1*	'OIL'	3*	NO /
'PROD4'	'G1'	5	31	1*	'OIL'	3*	NO /
'PROD5'	'G1'	16	17	1*	'OIL'	3*	NO /
'PROD6'	'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 /

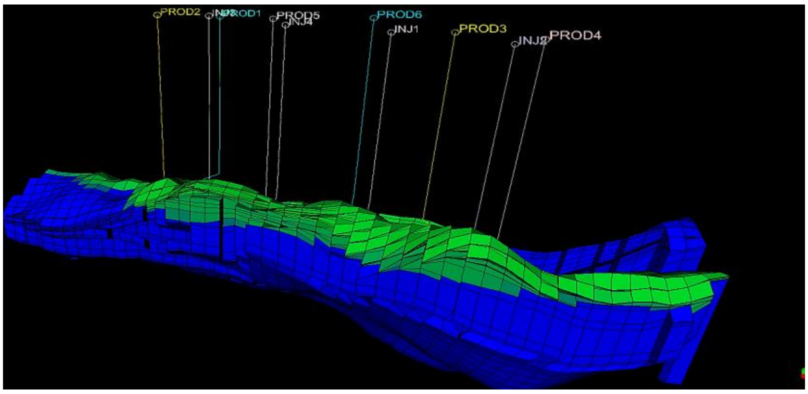

Fig. 6. A 3D model of gas injection

Table 4. Well specifications for gas injection

Well	Group	I	J	Depth	Phase	3*	Crossflow
'PROD1'	'G1'	11	26	1*	'OIL'	3*	NO /
'PROD2'	'G1'	20	13	1*	'OIL'	3*	NO /
'PROD3'	'G1'	12	21	1*	'OIL'	3*	NO /
'PROD4'	'G1'	5	31	1*	'OIL'	3*	NO /
'PROD5'	'G1'	16	17	1*	'OIL'	3*	NO /
'PROD6'	'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 /

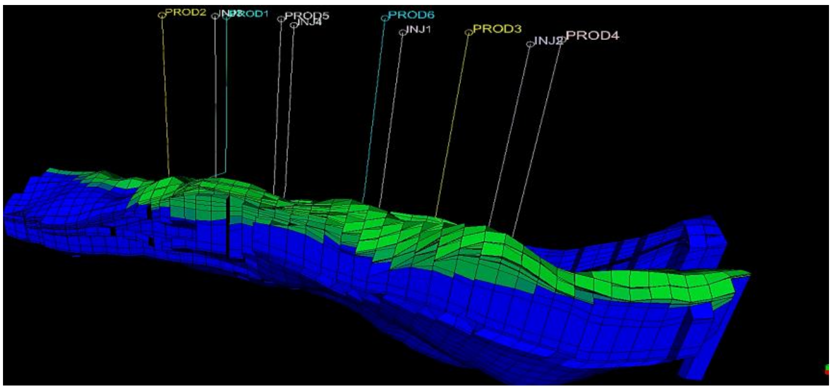

Fig. 7. A 3D model of WAG injection

Table 5. Well specifications for WAG injection

Well	Group	I	J	Depth	Phase	3*	Crossflow
'PROD1'	'G1'	11	26	1*	'OIL'	3*	NO /
'PROD2'	'G1'	20	13	1*	'OIL'	3*	NO /
'PROD3'	'G1'	12	21	1*	'OIL'	3*	NO /
'PROD4'	'G1'	5	31	1*	'OIL'	3*	NO /
'PROD5'	'G1'	16	17	1*	'OIL'	3*	NO /
'PROD6'	'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 /

3. RESULTS FROM NATURAL DEPLETION SIMULATION

3.1 Discussion on Natural Depletion Result

Table 6 presents the results of the natural depletion simulation using Schlumberger INTERSECT. The results show that the reservoir performance under natural depletion has a maximum field oil efficiency (recovery factor) of 14.3%, which is close to the initial recovery factor of 14.305% obtained from the oil field data. Therefore, the validity of the software has been ascertained. Additionally, at a field oil production rate (FOPR) of 800,000 stb/day, a plateau of 3 years was maintained. The total oil production time was 20 years, at a cumulative oil field production (FOPT) of 3,553 MMSTB.

From Fig. 10, it is observed that the field oil efficiency (recovery factor) gradually increases after 20 years having remained constant at 14.3%. However, analysis from Fig.11 shows that the cumulative oil production (FOPR) remained stable at 800,000 STB/Day until the 3 years where there was a sudden decline. This decline gradually continued until the 20th year.

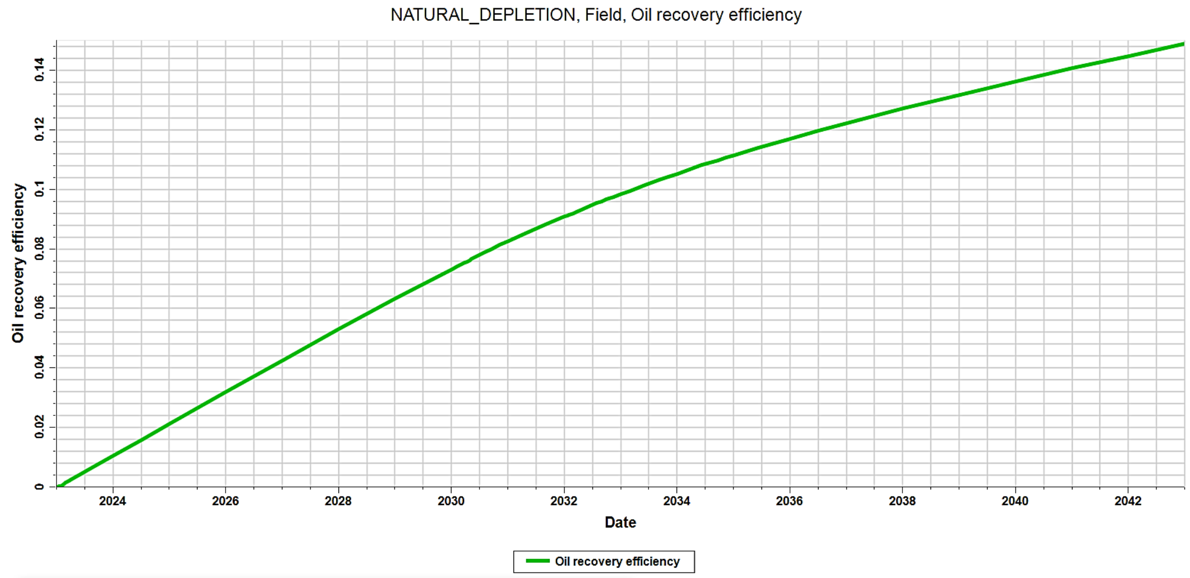

Fig. 8. Plot of FOE vs TIME (yrs) –natural depletion

Table 6. Natural depletion results

FOE (%)	FOPR (STB/Day)	FOPT (MMSTB)	Plateau (yrs)	Total Production Time (yrs)
14.3	800000	3,553	3	20

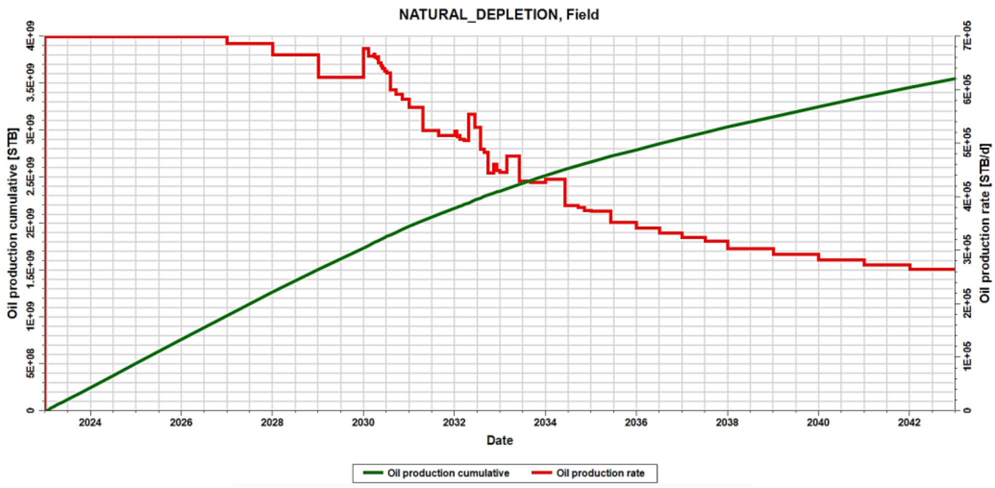

Fig. 9. Plot of FOPR & FOPT vs TIME (yrs) –natural depletion

3.2 Results from Waterflooding Simulation

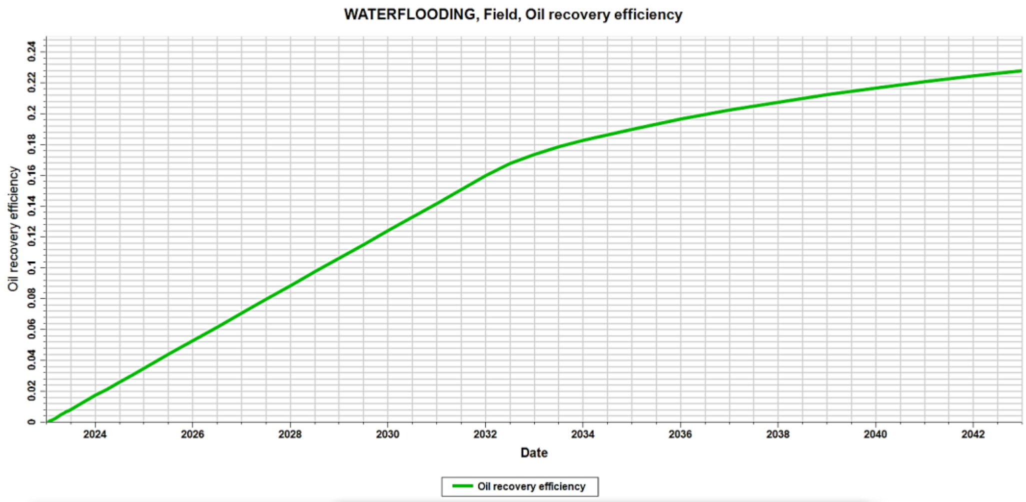

Fig. 10. Plot of FOE (recovery factor) vs TIME (yrs) – water injection

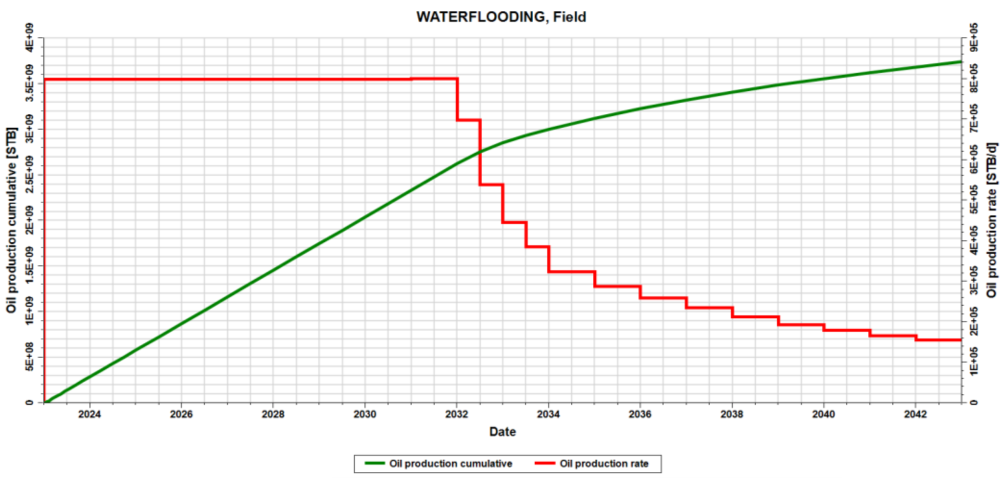

Fig. 11. Plot of FOPR & FOPT vs TIME (yrs) – water injection

3.3 Discussion on Waterflooding Result

From Table 7, the results show that the reservoir performance with waterflooding has a maximum recovery factor of 23%. Additionally, at a field oil production rate (FOPR) of 800,000stb/day, a plateau of 9 years was maintained. The total oil production time was 20 years, at a total oil field production (FOPT) of 3,746 MMSTB.

According to the analysis from Fig. 10, the field oil efficiency (recovery factor) gradually rises until the 9-year mark, at which point there is a slight decline. It continued rising steadily until it reached its highest point at 23 percent. Additionally, study of Fig. 11 reveals that the rate of oil production (FOPR) remains constant for a period of 9 years before gradually decline to 100,000 STB/Day and is maintained for 11 years. The total oil production increased gradually up till 3,746 MMSTB.

Table 7. Waterflooding results

FOE (%)	FOPR (STB/Day)	FOPT (MMSTB)	Plateau (yrs)	Total Production Time (yrs)
0.23	800,000	3,746	9	20

3.4 Results from Gas Injection Simulation

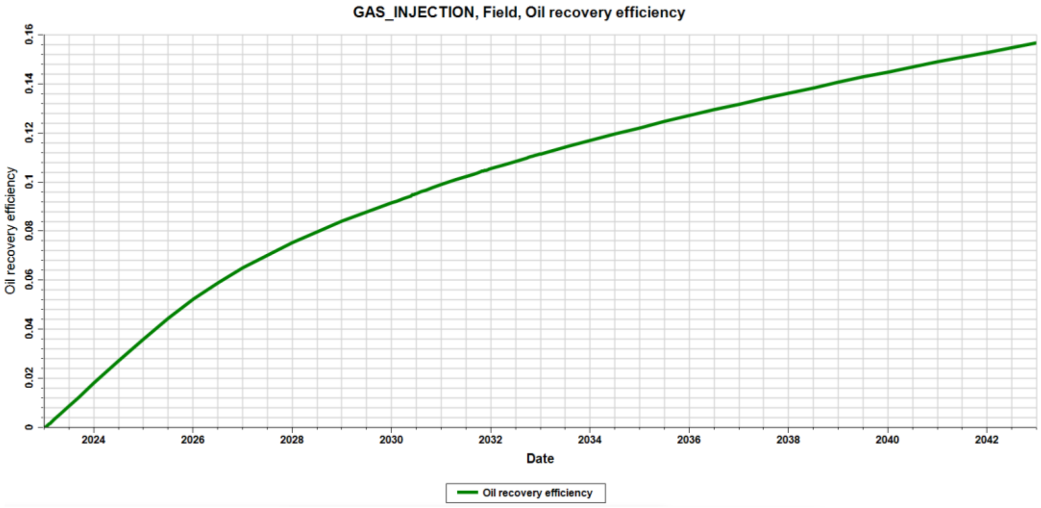

Fig. 12. Plot of FOE (Recovery Factor) vs TIME (yrs) – gas injection

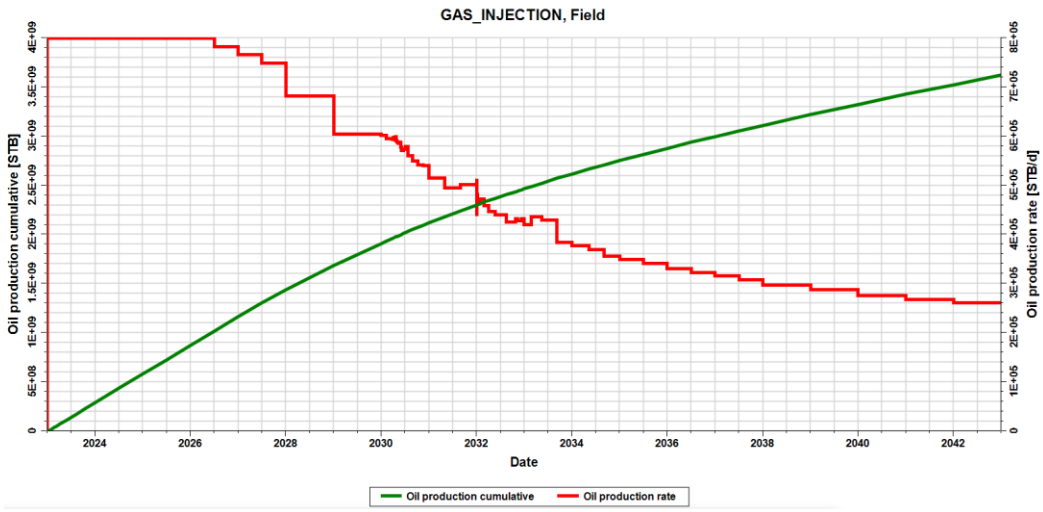

Fig. 13. Plot of FOPR & FOPT vs TIME (yrs) – gas injection

3.5 Discussion on Gas Injection Result

According to Table 8, there is a maximum recovery factor of 15 percent for reservoir performance with gas injection. A 3-year and 2 months plateau were also maintained at a field oil production rate (FOPR) of 800,000 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 3,606 MMSTB during a period of 20 years.

The field oil efficiency (recovery factor) continued to increase steadily until it peaked at 15 percent (Fig. 12). Furthermore, analysis of Fig. 13 shows that the rate of oil production (FOPR) initially remains constant for a brief period before steadily declining to 200,000 STB/Day and remaining constant for 11 years. The total oil production increased gradually up till 3,606 MMSTB.

Table 8. Gas injection results

FOE (%)	FOPR (STB/Day)	FOPT(MMSTB)	Plateau (yrs)	Total Production Time (yrs)
0.16	800,000	3,606	3.2	20

3.6 Results from WAG Injection Simulation

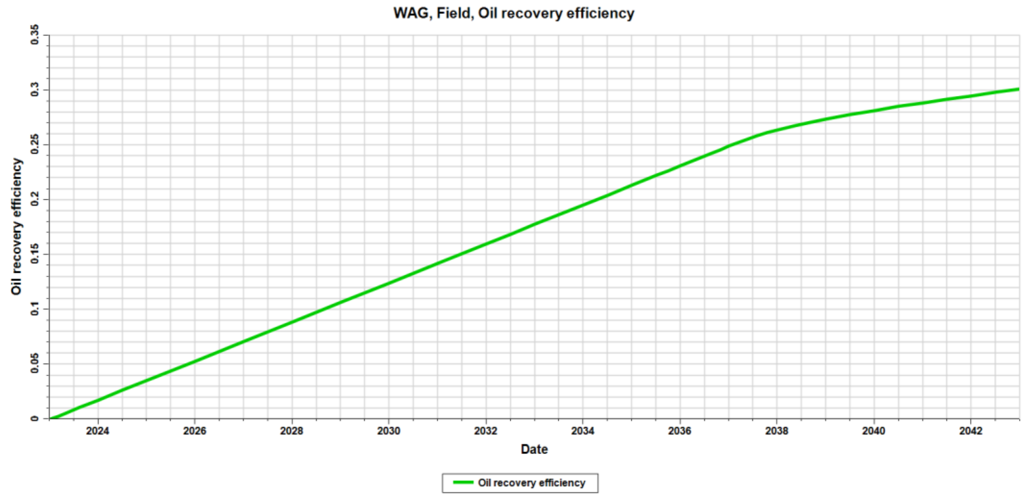

Fig. 14. Plot of FOE vs TIME (yrs) – WAG injection

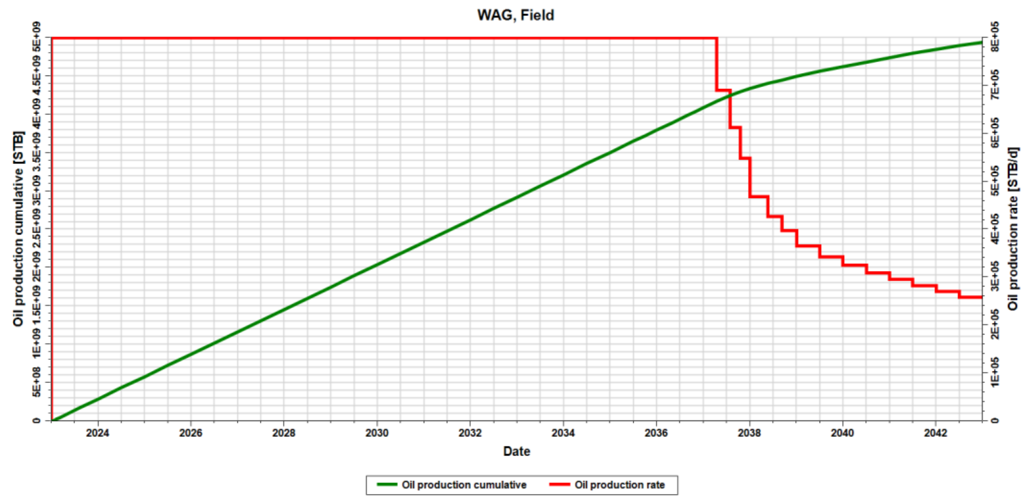

Fig. 15. Plot of FOPR & FOPT vs TIME (yrs) – WAG injection

3.7 Discussion on WAG Injection Result

From Table 9, the results show that the reservoir performance with WAG injection has a maximum recovery factor of 31%. Additionally, at a field oil production rate (FOPR) of 800,000 stb/day, a plateau of 14 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 20 years, at a total oil field production (FOPT) of 4 ,944 MMSTB.

The analysis from Fig. 14 shows that the field oil efficiency (recovery factor) gradually rises until it reached its highest point at 31 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 800,000 STB/Day and was constant for 14.7 years, after which it gradually declines to 300,000 STB/Day. The total oil production increased gradually up till 4 ,944 MMSTB.

3.8 Comparing Waterflooding, Gas and WAG Injections

FOE Comparative Analysis

Analysis from Fig. 16, shows that the field oil efficiency (recovery factor) for gas injection continuously increases along with that of waterflooding and WAG, until the 3.2-year, at which point it reduces steadily until it topped out at 15 percent. While for that for waterflooding the FOE continued rising until the 9-year mark, where it started to decline steadily until it reached its highest point at 23 percent. The FOE for WAG injection maintained its steady increase to the highest point of 31 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 31%, followed by waterflooding with 23% and the least is gas injection with 15% respectively.

Table 9. WAG injection results

FOE (%)	FOPR (STB/Day)	FOPT (MMSTB)	Plateau (yrs)	Total Production Time (yrs)
31	800,000	4 ,944	14.7	20

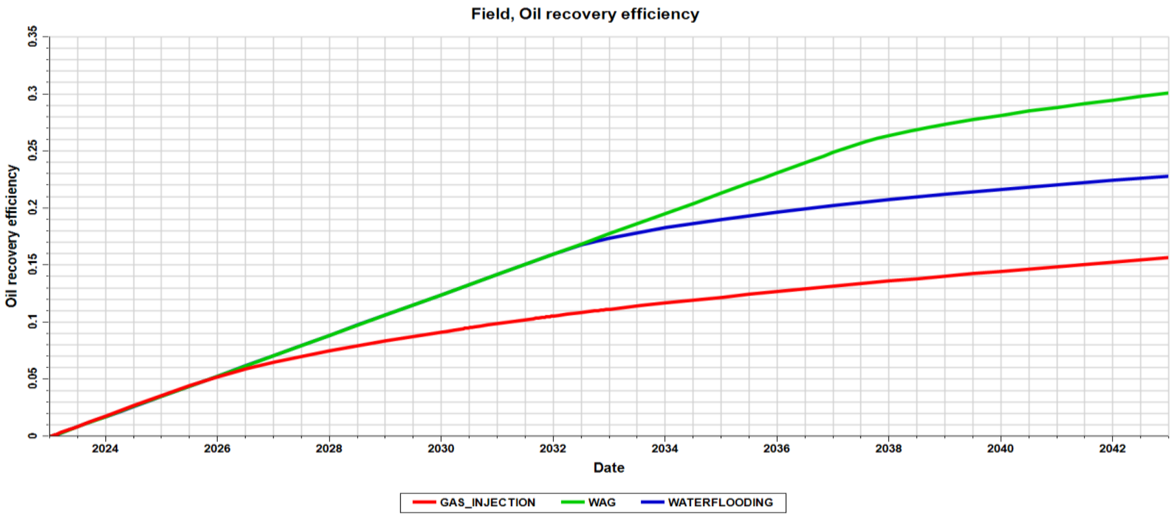

Fig. 16. Plot of FOE vs TIME (yrs) – Waterflooding, gas and WAG injection

Table 10. FOE results for waterflooding, gas and WAG injection

	FOE [Recovery factor] (%)	
Waterflooding	Gas injection	WAG injection
23	15	31

3.9 FOPR Comparative Analysis

Analysis from Fig.17 and Table 11 shows that the field production rate for WAG injection has the longest plateau of 14 years, while gas injection production rate lasted for just 3 years and 2 months. The production rate of waterflooding lasted for 9 years respectively.

3.10 FOPT Comparative Analysis

From Fig. 18 and Table 12, WAG had a total oil field production (FOPT) of 49,449 MMSTB, which was the highest, followed by waterflooding with 37,466 MMSTB. And gas injection had the lowest total oil field production of 36,063 MMSTB respectively.

3.11 FWPT Comparative Analysis

From Fig.19 and Table 13, waterflooding had a total field water production (FWPT) of 96,895 MMSTB, which was the highest, followed by WAG with 18,356 MMSTB. And gas injection had the least total field water production of 13,444 MMSTB respectively.

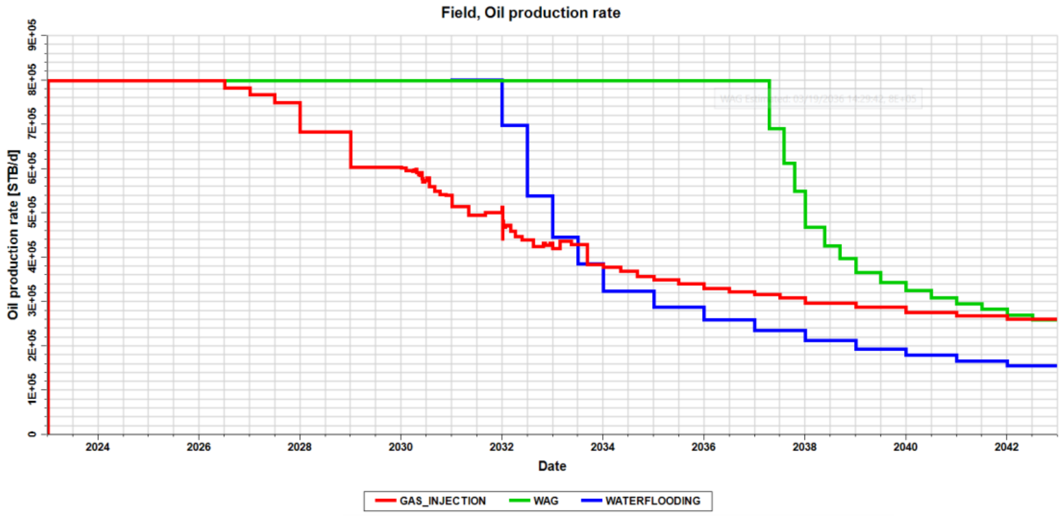

Fig. 17. Plot of FOPR vs TIME (yrs) – Waterflooding, gas and WAG injection

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

	FOPR [Plateau] (yrs)	
Waterflooding	Gas injection	WAG injection
9	3.2	14

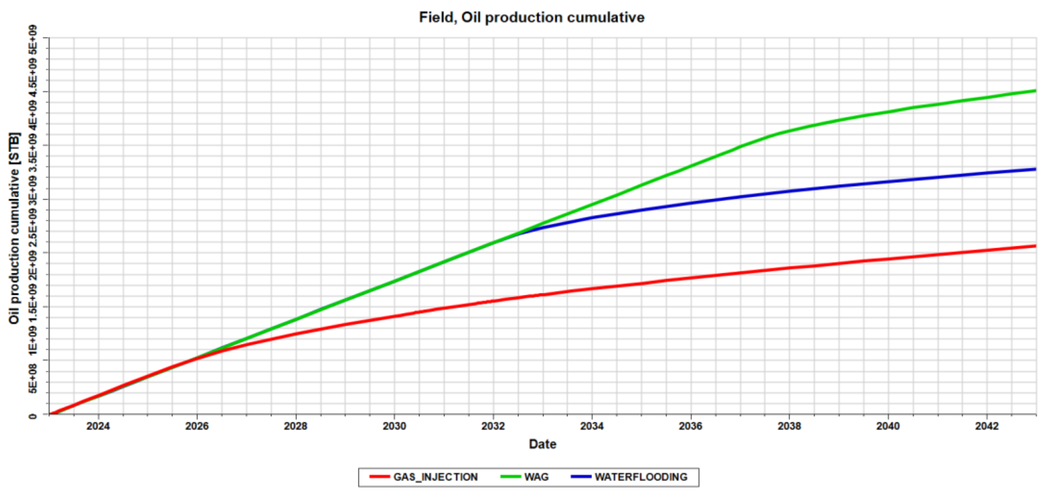

Fig. 18. Plot of FOPT vs TIME (yrs) – Waterflooding, gas and WAG injection

Table 12. FOPT results for waterflooding, gas and WAG injection

	FOPT (MMSTB)	
Waterflooding	**Gas injection**	**WAG injection**
37,466	36,063	49,449

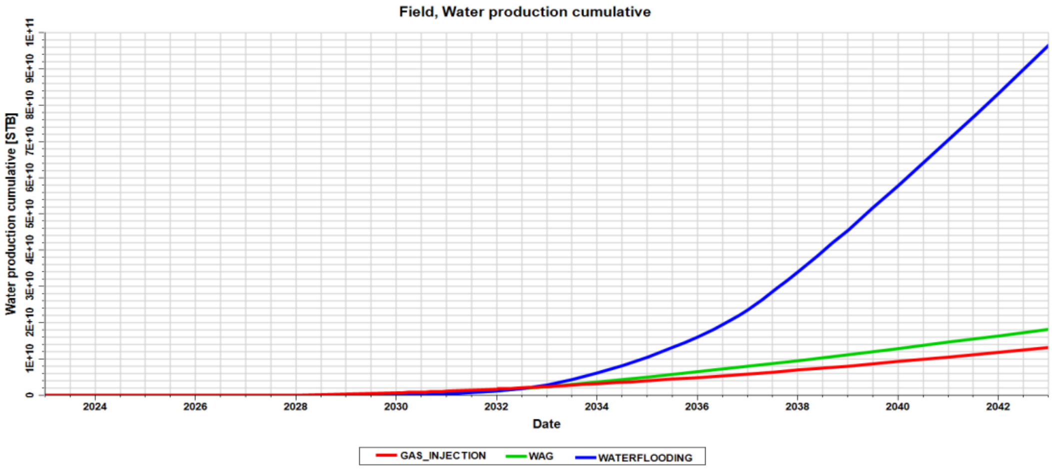

Fig. 19. Plot of FWPT vs TIME (yrs) – Waterflooding, gas and WAG injections

Table 13. FWPT results for waterflooding, gas and WAG injection

	FWPT (MMSTB)	
Waterflooding	**Gas injection**	**WAG injection**
96,895	13,444	18,356

4. CONCLUSIONS AND RECOMMENDATION

WAG injection is a tertiary oil recovery technique with increasing acceptability in the oil and gas industry due to its proven and successful oil recovery performance. Hence, this study has carefully examined the viability of the WAG injection method for oil recovery in 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 31%, a field oil production total (FOPT) of 4,944 MMSTB, a plateau time of 14 years and a field total water production (FWPT) of 18,356 MMSTB.

Waterflooding had a FOE of 23%, a FOPT of 37,466 MMSTB, a plateau time of 9 years and a field total water production (FWPT) of 96,895 MMSTB. Whereas gas injection had an FOE of 15%, a FOPT of 36,063 MMSTB, a plateau time of 3.2 years, and a field total water production (FWPT) of 13,444 MMSTB.

From comparative analysis of the three recovery methods, WAG injection outperformed both waterflooding and gas injection with the highest FOE of 31% and the longest plateau time of 14 years.

Therefore, the comparative analysis has demonstrated that WAG recovery method is the most effective recovery method, in comparison to waterflooding and gas injection.

The findings in this study are valuable for raising awareness among oil producers on the advantage of utilizing WAG injection method to optimize oil production in the Niger Delta. The finding of this study will provide petroleum engineers with the information they need to make informed decisions based on the effectiveness of the water-alternating-gas injection method for the optimal oil production in the Niger Delta.

It is recommended that a deep economic analysis be carried out to ascertain the competitive advantage of WAG application in the oil and gas industry.

COMPETING INTERESTS

Authors have declared that no competing interests exist.

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