Comparative studies of surfactant-enhanced-water, WAG and surfactant-enhanced-WAG injections in concurrent development of thin oil rim reservoir

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ABSTRACT

The goal of this paper is the comparative analysis of three injection fluid options: Surfactant-enhanced-Water (SeW), Water Alternating Gas (WAG) and Surfactant-enhanced-WAG (SeWAG). The objectives are to identify the best option with the highest oil and gas displacement efficiency and the best development strategy for optimum recoveries in concurrent development of an oil rim reservoir. The Eclipse simulator was used because of its robust ability in simulating various injection options of an oil rim reservoir in a green field. Four scenarios (base case/no injection, SeW, WAG and SeWAG injections) were simulated under the same conditions to determine injection option with the best displacement efficiency and recoveries of oil and gas. Statistical analysis using Pareto chart was performed for proper identification of the option with the best recoveries. The result showed that SeWAG injection ratio 1:4:2 and injection cycles 56 gave the best recoveries for oil and gas with displacement efficiency of 0.08 and 0.332 respectively, followed by SeW injection with values of 0.073 and 0.331 respectively, while WAG has the least performance. On the Pareto chart, SeWAG simulation result has the highest percentage among the options with the best recoveries of 3.35 MMSTB oil and 16.05 BSCF gas, which is 12.53% and 16.12% of oil and gas in place after 9.6% of oil and 15.1% of gas have been recovered by natural depletion. Hence, this study has shown that two stages of development strategy (combination of natural depletion and SeWAG injection when the reservoir pressure is depleted) give cumulative effect for optimal recoveries in concurrent development of oil rim reservoir.

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1. Introduction

Thin oil rim reservoirs with overlying large gas cap are one of the complex reservoirs [1]. Developing thin oil rim reservoirs requires

careful consideration of the optimum timing for oil and associated gas cap production to maximize the economic value of the asset [2]. Oil rim reservoir with gas cap can be devel-

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Nomenclature

API	American Petroleum Institute	MSCF/STB	Thousand standard cubic feet per stock tank barrel
bbl	Barrel	OGR	Gas wetness (STB/MSCF)
Bgi	Initial gas formation volume factor (bbl/scf)	OWC	Oil-water-contact
BHP	Bottom hole pressure (psia)	R _{fgas}	Gas recovery factor
Boi	Initial oil formation volume factor (bbl/stb)	R _{foil}	Oil recovery factor
BSCF	Billion standard cubic feet	R _{si}	Solution gas-oil ratio (SCF/STB)
EOR	Enhanced oil recovery	SCF/D	Standard cubic feet per day
FWCT	Field water cut total	SeW	Surfactant-enhanced-water
g/scc	Gram per solution critical concentration	SeWAG	Surfactant-enhanced-water-alternating gas
GOC	Gas-oil-contact	STB/D	Stock tank barrel per day
GOR	Gas-oil ratio	THP	Tubing head pressure (psia)
md	Milli Darcy	WAG	Water-alternating-gas
MMSCF	Million standard cubic feet	WCT	Water cut (%)
MSTB	Thousand stock tank barrel		
MMSTB	Million stock tank barrel		

oped concurrently under the conventional / traditional natural pressure depletion development option or by injection options [3]-[9]. The best development option is selected through the evaluation of various development options with numerical simulation [10]-[15]. However, examples of concurrent development of gas cap and oil reservoir in the world are very few [16].

One of the major problems being faced by the oil industry across the globe is little or no discovery of new reserves of oil and gas in addition to the existing ones. In addition, majority of the world's existing oil rim reservoirs with large gas cap have their gas caps retained for a long time for the purpose of using the gas caps energy to produce the oil in the reservoir. Since the rate of new discoveries is very minimal, then there is urgent need to look into the abundant gas cap that is associate with oil rim reservoirs. The goal of the search is to find the best way of producing the gas cap and the oil simultaneously in such a way the technical challenges that are associated with such development are either eliminated or minimized to have an optimum oil and gas recovery factors. Hence, concurrent development of oil and gas is an option. This method of concurrent development of thin oil rim reservoir requires diligent and careful management of reservoir to optimize recoveries of oil and gas concurrently. However, production of gas and oil concurrently, decreases the reservoir pressure and the rate of water influx continues to climb [17]. These are technical challenges that can hamper the optimum recovery of oil from thin oil column and gas from the large gas cap in a natural depletion development option.

Enhanced Oil Recovery (EOR) technology has demonstrated promising results in improving oil recovery factor [18]. Water-

Alternating-Gas (WAG) injection is a type of EOR, which involves injection of water and gas in a sequential ratio for a period of time in cycles. Surfactant-enhanced-WAG (SeWAG) injection is a novel enhanced oil recovery technique that combines surfactant and WAG injections. It involves sequential injection of an aqueous solution of low surfactant concentration. Thereafter gas (CO₂) and water are injected one after the other alternatively based on injection fluids ratio for a specific period of time in cycles. SeWAG combines the advantages of surfactant-enhanced-Water (SeW) and WAG injections. Unlike WAG injection that suffers gravity segregation and viscous fingering often in heterogeneous reservoir [19]. Moreover, enhanced oil recovery methods are the techniques used for maximizing oil recoveries [20].

The goal of this paper is the comparative study on three injection options (SeW, WAG and SeWAG). The objectives are to identify the best option with highest oil and gas displacement efficiency and the best development strategy for optimum recoveries in concurrent development of an oil rim reservoir.

2. Methods

In WAG injection, the recovery mechanism is the combined effects of oil swelling, viscosity reduction by CO₂ and pressure maintenance by water [18]. Thus increases oil mobility and wettability alteration [21]. The fluid mobility is expressed as:

$$\lambda_o = \frac{k_o}{\mu_o} = \frac{kk_{ro}}{\mu_o} \quad (1)$$

$$\lambda_w = \frac{k_w}{\mu_w} = \frac{kk_{rw}}{\mu_w} \quad (2)$$

$$\lambda_g = \frac{k_g}{\mu_g} = \frac{kk_{rg}}{\mu_g} \quad (3)$$

Where λ_o , λ_w , and λ_g are the mobility of oil, water, and gas respectively; k_o , k_w , and k_g are the effective permeability of oil, water, and

gas respectively; k_{ro} , k_{rw} , and k_{rg} are the relative permeability of oil, water, and gas respectively; k is the absolute permeability.

SeW injection is another example of EOR in which little concentration of surfactant (surface active agent) is added to an aqueous fluid to sweep oil or gas in the microscopic and megascopic pore spaces of the reservoir rock. Its recovery mechanism is the effects of reduced interfacial tension between the oil-water phase and oil-gas phase by the surface active agent, thus improves oil mobility or gas mobility. The reduction of the interfacial tension by surfactant can best be understood by relating the capillary number to residual oil saturation. The relationship is given as:

$$N_c = \frac{\mu v}{\sigma} \quad (4)$$

Where N_c is the capillary number, μ is the viscosity of the injection fluid, v is the linear advance rate, and σ is the oil-brine interfacial tension.

The capillary number is a dimensionless parameter that measures the ratio of viscous forces to capillary forces. In black oil simulator, capillary number is expressed as:

$$N_c = \frac{|k \cdot \text{grad} P|}{ST} C_{\text{unit}} \quad (5)$$

Where k is the permeability, P is the potential, ST is the interfacial tension, C_{unit} is the conversion factor depending on the unit used.

$$|k \cdot \text{grad} P| = \sqrt{(k_x \cdot \text{grad} P_x)^2 + (k_y \cdot \text{grad} P_y)^2 + (k_z \cdot \text{grad} P_z)^2} \quad (6)$$

Where for cell i ,

$$k_x \cdot \text{grad} P_x = 0.5 \left[\left(\frac{k_x}{D_x} \right)_{t-1,t} \cdot (P_t - P_{t-1}) + \left(\frac{k_x}{D_x} \right)_{(t,t+1)} \cdot (P_{t+1} - P_t) \right] \quad (7)$$

Similarly, for the y and z directions, the $\frac{k}{D}$ value is calculated in an analogous manner to the transmissibility and depends on how the geometry was specified. Residual oil saturation in the pore space of reservoir rock can be de-saturated to half by simply increasing the capillary number to 1000 times by water flooding [21]-[23]. However, it is practically impossible to increase the capillary number to 1000 times by water flooding but with addition of low concentration surfactant; it is achievable [24]. Hence, the interfacial tension is reduced and oil mobility gets improved in both microscopic and megascopic

pore spaces of a reservoir rock are enhanced due to reduced capillary trapping.

2.1. Dynamic Modeling and Simulation

For the purpose of this study, Static models built in Petrel using a case study data from a green field "x" in the Niger Delta Basin of Nigeria were exported to Eclipse software for dynamic modeling and simulation. Model initialization was then carried out to estimate the fluids in place (HCIIP) for the reservoir. The constructed model was in grid unit of feet with the following grid axes with respect to (WRT Map) the grid coordinates and dimensions: 91 x 74 x 20 and 134680 grid cells; the reservoirs specifications have been tabulated in Table 1.

2.2. Case Definition

Simulation start date was defined for the cases depending on the well's production start date. Grid dimensions (in x , y and z directions) were specified (Table 1). Cartesian grid and corner point grid geometry options were chosen for more accurate reservoir modeling. Reservoir fluid phases (water, oil, gas, dissolved gas and vaporized oil) were defined. A fully implicit solution method was used for all the runs to guarantee convergence of the solution type.

2.3. Model Initialization

The model was initialized under hydrostatic equilibrations, the contact used were carried forward from the static modeling. The initial reservoir pressure, datum depth, Gas-Oil-Contact (GOC) depth, and Oil-Water-Contact (OWC) depth are 3518psia, 6025ft, 6025ft and 6064 respectively. It is important to state that the initial parameters were taken in accordance with the standard reservoir engineering practice; Reservoir engineers take GOC depth as datum depth if the reservoir is a saturated reservoir when there is no available information about the datum depth, which was the reason for 6025ft taken as our datum depth. The initial volume of oil (STOOIP) and initial volume of gas (GIIP) are 44.29 MMSTB and 18.1BSCF respectively. Carter-Tracy analytical aquifer was attached as bottom drive to sustain the energy of the reservoir. The aquifer permeability, aquifer's angle, compressibility and thickness are 88.13md, 180, 3.20×10^{-6} and 45ft respectively.

Table 1 Simulation grid dimensions

Reservoir	Grid dimensions (i/j/k)	Number of active cells	Number of inactive cells
"x" Niger Delta	91*74*20	134680	8138

Table 2 Development and prediction strategies

Prediction strategies	Values
Oil production off-take rate	2000 STB/D
Minimum oil production rate	100 STB/D
Maximum water cut	95%
Minimum THP	150 psia
Minimum BHP	1000 psia
Start of production	1 st of January 2017
End of prediction	1 st of January 2032
Prediction duration	15 years
Gas production off-take rate	5 MSCF/D
Minimum gas production rate	1 MSCF/D

2.4. Development and Predictions Strategies

Concurrent oil and gas development were carried out on “x” field in the Niger Delta Basin. One vertical oil, gas and injection well each was drilled into the reservoir to develop the reservoir concurrently. The set economic and operational limits/constraints are shown in Table 2. Predictions and development strategies were done in different scenarios: (a) the do nothing / base case (when there was no injection) and (b) the SeW, WAG and SeWAG injection cases.

In the base case scenario, one oil and gas well each was developed concurrently under natural depletion for 15 years to identify their production profiles and recoveries at the end of prediction time. The result of the base case was compared with the SeW, WAG and SeWAG injections. Eclipse simulated results for each injection case was compared using Excel to plot the comparative plots for cumulative oil and gas produced, and Eclipse was used to generate 3D-model of the

reservoir at initial and final stages of development. Pareto chart was used to analyze Eclipse simulated result under the three injection options, to identify the order of their recovery efficiency. The displacement efficiency of each injection fluid option was computed as follows:

$$E_D = \frac{\text{Volume of oil at start of flood} - \text{remaining oil volume}}{\text{Volume of oil at start of flood}} \quad (8)$$

$$E_D = \frac{(\text{Pore volume})\left(\frac{S_{oi}}{B_{oi}}\right) - (\text{Pore volume})\left(\frac{\bar{S}_o}{B_o}\right)}{(\text{Pore volume})\left(\frac{S_{oi}}{B_{oi}}\right)} \quad (9)$$

$$E_D = \left[\frac{S_{oi}}{B_{oi}} - \frac{\bar{S}_o}{B_o} \right] / \left[\frac{S_{oi}}{B_{oi}} \right] \quad (10)$$

Where S_{oi} is the initial oil saturation, at start of flood (bbl/STB), B_{oi} is the oil formation volume factor at start of flood (bbl/STB) and $\bar{S}_o$ is the average oil saturation in the flood pattern at a particular point during the flood.

Total volume of 0.4866 MMSCF miscible non-hydrocarbon gas (CO_2) and 0.24333 MMSTB of water was injected alternately in the ratio of 4:2 for 9 cycles per year respectively at OWC at minimum miscible pressure of 2850 psia. The injection rate was 2000 SCF/D and 2000 STB/D for CO_2 and water respectively for 15 years under WAG injection. Similarly, WAG injection was repeated when injection well was placed at GOC. Total volume of 109.56 MSTB of fluid with 0.8% concentration of surfactant (Table 3) ranging from 0.001-0.5 g/scc as defined in Eclipse was injected into the reservoir for 15 years at the rate of 2000 STB/D under surfactant injection scenario.

Table 3 Reservoir and well properties

Parameters	Units	Reservoir X
Dip Angle	degree	1.33
Gas Wetness (OGR)	STB/MSCF	0.699
Oil Column Height	feet	39
Gas Cap Size (M-Factor)		1.43
Aquifer Height to Hydrocarbon Thickness Ratio (Aqfac)		1.15
Horizontal Permeability (k_x , k_y)	md	613
K_v/K_h		0.02
Wellbore Diameter	feet	3.19
Oil Density	lb/cu.ft	39.5
Oil rate (Q_o)	STB/D	2000
K_{rw} (Rel. Perm to Water)		0.18
WGR control (*Rsi)		0.2
BHP (Bottom hole Pressure) TARGET	psia	3000
API		32
surfactant concentration	%	0.8
Formation water salinity	ppm	70000
surfactant injection rate and other fluid	STB/day	2000
Total volume of surfactant injected	MSTB	109.56
Oil viscosity	cp	0.26307
oil saturation	%	0.115
Aquifer strength	180 deg	moderate
GOC (Gas-Oil-Contact)	ft	6025
OWC (Oil-water-Contact)	ft	6064
Initial Reservoir Pressure	Psia	3518
Initial oil formation volume factor (B_{oi})	SCF/STB	1.141
Initial gas formation volume factor (B_{gi})	bbl/SCF	0.0096
Solution gas-oil ratio (R_{si})	SCF/STB	380

Low surfactant concentration was used in this study because it has been shown by Sheng [24] that low surfactant concentration gives optimum recovery. During SeWAG injection, total volume of 0.104286 MMSTB of aqueous fluid with 0.8% concentration of surfactant was injected alternately with 0.41714 MMSCF volume of miscible non-hydrocarbon gas (CO_2), and 0.208572 MMSTB volume of water respectively at OWC at the rate of 2000 STB/D, 2000 SCF/D, and 2000 STB/D for 15 years. The ratio of SeWAG injection was 1:4:2 with injection fluid sequence of Surfactant/ CO_2 /Water were injected for 15 years in 56 cycles. Similar, SeWAG injection was repeated when the injection well was placed at GOC.

Surfactant of 0.8% concentration was used during SeW injection and SeWAG injection according to Hirasaki et al. [25] that surfactant of low concentrations of 0.8 and 0.9% recovers better. One injector well and one production well each was used for the development of "x" reservoir in the green field, Niger Delta, at the GOC and OWC positions (Fig. 1). Several simulation runs were carried out. The predictions for the future performance were done for the next fifteen years for each case (Fig. 2). Statistical Pareto analysis was carried out on the simulated results for the three injection

options to determine the injection option and fluid with the best displacement efficiency for optimum oil and gas recovery factors.

3. Results and Discussion

3.1. Base Case Scenario

In the base case scenario, the reservoir was developed for the very first time because it was a green field. It was a concurrent development; the gas was produced from the gas cap and the oil from the thin oil column concurrently under natural pressure without injection. The oil well produced at constant rate of 2000 STB/D for just one year two months and the total cumulative oil production from the well was 80700 STB (Fig. 3). After this period of constant production rate, the well began to experience abnormal rise in GOR from less than 2 MSCF/STB to 69 MSCF/STB (Fig. 3), and water cut set in. The well pressure was forced down drastically from over 3,440 Psia to 2280 Psia (Fig. 3).

As the oil production continued for few days, the well pressure rose up a bit to 2460 psia and later began to decline gradually to 1880 Psia toward the end. However, the GOR decreased gradually as from year 2018 to 2020, from 69 MSCF/STB to 5 MSCF/STB (Fig. 3).

Fig. 1 Ternary diagram showing fluid initially in place saturations and development wells for "x" reservoir in the green field, Niger Delta Basin

Fig. 2 Final ternary diagram showing fluid saturations after the end of fifteen years of development of "x" reservoir in the green field, Niger Delta Basin

Table 4 Result of the base case scenario and the oil and gas initial in- place

Base Case			Dynamic Volumes	
Cum Oil (MMSTB)	Cum Gas (BSCF)	WCT (%) @ EOP	Oil (MMSTB)	Gas (BSCF)
2.57	15	0.61	44.29	63.3

Fig. 3 Oil well production profile plots for the base case in "x" reservoir, green field Niger Delta, Nigeria **Fig. 4** Gas well Production Profile Plot for base case in "x" field Niger Delta, Nigeria

The GOR further dropped gradually as production continued at constant value of 2 MSCF/STB. The water cut from the well

continued to increase rapidly to a value of 0.61% (Fig. 3). As concurrent production continued till 2032, a total oil production of

2.57 MMSTB (Table 4) was recovered under the base case scenario from the STOIIP, 44.29 MMSTB. The gas was produced at a constant rate of 5 MSCF (Fig. 4) from the gas cap same time as the oil was being produced under natural pressure.

The result (Fig. 4) showed constant rate of production without any distortion in production pattern unlike that of oil well. Furthermore, gas production total increased gradually at constant rate from year 2017 to 2032. The field oil production total rapidly changed from its normal path due to sudden increase in GOR thus, caused oil shrinkage. The oil shrinkage resulted to oil production decrease. However, the gas production total was not affected by high GOR, water cut and well pressure decline; rather there was steady increase in gas cumulative production. In the base case, the well produced 2.75 MMSTB cumulative oil with recovery factor of 5.8% while cumulative gas produced was 15 BSCF with a recovery factor of 23.69% (Table 5).

3.2. The Injection Scenarios

The three injection scenarios gave additional cumulative increase when injections were carried out after the recoveries of oil and gas by the base case. The remaining oil and gas after base case recovery at the start of each injection case was 41.72 MMSTB and 48.3 BSCF respectively. During SeWAG injection of ratio 1:4:2 for 14 weeks complete cycle, the Eclipse model result showed that a total of 3.35 MMSTB and 3.21 MMSTB of oil were produced when injection wells were placed at OWC and GOC respectively (Table 5). SeWAG ratio 1:4:2 was used because it has been shown in [9] that the ratio 1:4:2 gave the best optimum recovery factor for oil and gas in the simulation studies of various SeWAG ratios in concurrent development of oil rim reservoirs. However, a total of 14.74 BSCF and 16.05 BSCF of gas was produced from the gas cap during concurrent production by SeWAG injection at OWC and GOC respectively.

The Eclipse model result for SeW injection showed that total 3.05 MMSTB and 2.89 MMSTB of oil was recovered from the oil column when SeW was injected at OWC and GOC respectively (Table 5). However, 15.11 BSCF and 16.02 BSCF of gas total were produced from the gas cap by injecting surfactant at OWC and GOC respectively. Under WAG injection, Eclipse simulated result showed that a cumulative volume of 2.87 MMSTB and 2.73 MMSTB of oil were produced

from the oil column when WAG was injected at OWC and GOC respectively. However, a cumulative volume of 14.63 BSCF and 15.94 BSCF of gas were recovered from the gas cap when WAG injection of WAG ratio 4:2 at 12 weeks for a complete cycle was injected at OWC and GOC respectively (Table 5) for 15 years. WAG ratio 4:2 was used; since according to [9], WAG ratio 4:2 gave the best optimum recovery factor for oil and gas in the simulation studies of various WAG ratios. The result of the simulation showed that SeWAG oil recovery factor increased by 32.75% and 25.36% at OWC and GOC respectively after concurrent production under base case, 18.8% and 12.45% for surfactant injection; 11.7% and 6.21% for WAG injection (Table 5). The simulation result for gas cap showed that SeWAG gas recovery factor increased by 0.97% and 7.05% at OWC and GOC respectively after concurrent production by natural pressure, surfactant gave increase of 0.75% and 6.8% gas recovery factor at OWC and GOC respectively, WAG gave percentage increase of -2.47% and 6.29% at OWC and GOC respectively.

3.3. Comparative Studies of SeW, WAG and SeWAG Injections

3.3.1 Oil Column: The results of Eclipse simulations for reservoir "x" showed that concurrent development of oil and gas by SeWAG injection gave the best oil recovery factor of 7.75%, which is about 32.75% additional oil increase when SeWAG was injected at OWC (Table 5) compared to surfactant and WAG injections results. However, the other two EOR injection methods also recorded higher oil recovery factor when injection of fluids was at OWC compared to GOC but SeWAG gave the overall best performance. This observation shows that SeWAG is very effective in concurrent development of oil rim reservoir compared to WAG and surfactant injections. This effective action of SeWAG must have been from the combined strength of surfactant and WAG, which must have augmented the disadvantages that would have been inherent if it were to be either surfactant or WAG that was injected. The result shows that SeWAG injection has ability to de-saturate residual oil within the pore spaces of oil rim reservoir than SeW and WAG injections. The result also shows that SeWAG injection gives good wetting ability to make close contact with the reservoir rock. Thus, reduced the contact angles between the residual oil saturation in

Table 5 Summary of the comparative results under base case, SeW, WAG, SeWAG, development options for thin oil rim for reservoir “x” in the green field, Niger Delta Basin, Nigeria

	Base case	Development Cases					
		WAG G/W injection @ OWC	WAG G/W injection @GOC	SeW injection @ OWC	SeW injection @GOC	SeWAG injection @ OWC	SeWAG injection @ GOC
CUM oil (MMSTB)	2.57	2.87	2.73	3.05	2.89	3.35	3.21
Cum Gas (BSCF)	15	14.63	15.94	15.11	16.02	14.74	16.05
WCT (%)	0.61	0.46	0.55	0.26	0.25	0.26	0.31
Rfoil (%)	5.8	6.48	6.16	6.89	6.53	7.70	7.25
Rfgas (%)	23.69	23.11	25.18	23.87	25.31	23.92	25.36
Oil%increase	-	11.7	6.21	18.8	12.45	32.75	25.00
Gas%increase	-	-2.47	6.29	0.75	6.8	0.97	7.05
GOR (MSCF/STB)	1.75	3.21	3.05	1.65	1.69	1.64	1.67

the pore spaces of reservoir rock than SeW and WAG injection options. Hence, oil mobility and sweeping efficiency were observed to be highest in SeWAG injection than surfactant and WAG injection options.

The comparative plot (Fig. 5) for the cumulative oil production under the three EOR injection cases buttresses the facts earlier observed that SeWAG has the highest cumulative oil production of 3.35 MMSTB because of its combined effect on residual oil recovery. It means SeWAG has the best oil and gas recoveries optimization in concurrent development of oil rim reservoir compare to SeW and WAG injection options. The three techniques have higher values of oil recovery factors when injections were at OWC while the values are lower when injections are done at

GOC. The Pareto analysis and comparative plot showed that SeW has the second best oil recovery factor of 3.05 % when injection was at OWC while WAG has 2.78% (Table 5) oil recovery factor. SeWAG injection gave highest cumulative oil recovery at lower number of cycles compare to WAG injection that required higher number of cycles as shown in Fig. 5. In the same year (2028) of the simulation for future prediction, SeWAG injection at OWC produced 25 MMSTB cumulative oil under 42 SeWAG cycles as shown in Fig. 4, while in WAG injection at same OWC for the same year, it took 48 WAG cycle to produce 2.2 MMSTB cumulative oil production. A value far less than the one obtained under SeWAG injection for the same year (see Fig. 5).

Fig. 5 Comparative plot of cumulative oil production profile for three injection scenarios at OWC and GOC injection positions for “x” reservoir in the green field Niger Delta, Nigeria

Fig. 6 Comparative plot of Cumulative oil production profile for three injection scenarios at OWC and GOC injection positions for “x” reservoir in the green field Niger Delta, Nigeria

3.3.2 Gas Cap: Pareto chart for the various injection fluid options at OWC shows that SeWAG injection has 17.9% optimization effect on gas recovery factor followed by SeW which has value of 17.5% and WAG comes last with a value of 16.3% (see Fig. 6). SeWAG injection at GOC still shows highest optimization effect on gas recovery among the three injection fluid options. For injection at GOC, SeWAG optimization effect on Pareto chart was still the highest with a value of 16.9%, SeW has a value of 16.3% and WAG was the least with a value of 14.3% (Fig. 6).

The result of Eclipse simulator for the gas cap in concurrent development of oil rim

reservoir shows observations similar to that of oil column except for the injection position at GOC gave better optimum gas recovery factor of 25.36% with additional 7.05% increase in recovery factor (Table 4) than OWC, for all the three EOR injections. Comparative plot (Fig. 7) and Pareto analysis of the Eclipse simulated results for gas recovery factor in concurrent development of oil rim showed that SeWAG injection at GOC has the highest gas recovery factor optimization effect of 17.3% than SeW and WAG that are 17.2% (Fig. 8). WAG injection at OWC has the least ability to recover gas from the gas cap in concurrent development of oil rim.

Fig. 7 Comparative plot for Cumulative gas production profile for three injection scenarios at OWC and GOC injection positions for reservoir "x" in the green field Niger Delta, Nigeria

Fig. 8 Comparative plot of Cumulative gas production profile for three injection scenarios at OWC and GOC injection positions for "x" reservoir in the green field Niger Delta, Nigeria

Fig. 9 Comparison of water cut for fifteen prediction years for the three injection options and base case

3.3.3 Water Cut, Reservoir Pressure and Gas-oil-ratio: The field water cut total (FWCT) result for the base case was 0.61. However the commencement of injection in the three injection options scenarios, at the time of water breakthrough occurrence in the base case option helped the FWCT to reduce (Fig. 9). The effects of the three injection fluids in each scenario started to be felt as from 2021; that is, almost after one year and half that injection commenced. Out of the three injection options, SeWAG predicted simulation result gave the least FWCT of 0.25, SeW was 0.26, and WAG injections was 0.46. The results show that SeWAG has the best ability to delay early water cut and reduce FWCT among the three injection options, in concurrent development of oil rim reservoir. Surfactant enhanced water injection was second while WAG injection simulation result shows that WAG has the least ability of delaying early water breakthrough and ability to reduce FWCT.

The ability of each injection option in reducing FWCT resulted to each injection

option's ability to improve reservoir pressure as shown in Fig. 10. It was observed that SeWAG improved the reservoir pressure best from 2790 psia to 2900 psia compared to the two other injection options (Fig. 10). SeW injection improved the reservoir pressure from 2790 psia to 2860 psia, and WAG injection improved reservoir pressure from 2790 psia to 2840 psia as shown in Fig. 10.

The predicted simulation result for the three injection options in concurrent development of oil rim reservoir showed that SeWAG injection was able to reduce the gas-oil-ratio (GOR) lowest than SeW and WAG injections. SeWAG reduced GOR to 1.64 MSCF/STB, SeW injection reduced GOR to 1.65 MSCF/STB, and WAG injection reduced GOR to 1.7 MSCF/STB from the base case value of 1.75 MSCF/STB as shown in the comparative plot of GOR for the injection options (Fig. 11). This observation from the GOR result shows that SeWAG injection has the best retardation ability for oil shrinkage among the three injection options; thus, SeWAG gave the best support for concurrent development of oil rim reservoir with the highest optimization effect on recoveries than SeW and WAG.

Fig. 10 Comparative plot of reservoir pressure for fifteen prediction years for the three injection options and base case

Fig. 11 Comparative plot of GOR for fifteen prediction years for the three injection options and base case

Table 6 Oil and gas displacement efficiency for different scenarios

Injection fluid (EOR)	Volume of oil at start of flooding (MMSTB)	Volume of oil recovered (MMSTB)	Volume of Gas at start of flooding (BSCF)	Volume of gas recovered (BSCF)	E_D for oil	E_D for gas
WAG @ OWC	41.72	2.87	48.3	14.63	0.069	0.302
WAG @ GOC	41.72	2.73	48.3	15.94	0.065	0.33
SeWAG @ OWC	41.72	3.35	48.3	14.74	0.08	0.305
SeWAG @ GOC	41.72	3.21	48.3	16.05	0.077	0.332
SeW @ OWC	41.72	3.05	48.3	15.11	0.073	0.313
SeW @ GOC	41.72	2.89	48.3	16.02	0.069	0.331

 E_D : Displacement Efficiency

3.4. Displacement Efficiency

The result of the oil and gas displacement efficiency from the thin oil column and gas cap in the oil rim reservoir in a concurrent development showed that SeWAG has oil and gas displacement efficiency of 0.08 and 0.332 respectively (Table 6), which is the highest displacement efficiency among the three EOR cases considered in this study.

The displacement efficiency result of oil in this study is lower than gas. This observation gave a reflection of the total oil recovered by SeWAG to be 12.53% (Fig. 12) of the initial oil in-place, which is lower than gas being 16.1% (Fig. 9) of the initial gas in-place. However, for effective recovery of oil and gas in concurrent

development of oil rim reservoir, it is better to develop first with natural depletion and later apply SeWAG injection (Figs. 12 and 13) after reservoir pressure is depleted, water cut set-in, and GOR is high, to have additional recovery for optimum concurrent development.

SeW showed oil and gas displacement efficiency values of 0.073 and 0.331 respectively (Table 6) with WAG injection having the least values, 0.069 and 0.302 for oil and gas respectively. The displacement efficiency of each EOR is determined by the combining effects of the fluid's ability to wet the reservoir rock to make close contact that subsequently reduce the contact angle between the residual oil saturation in the pore spaces of the reservoir rock.

Fig. 12 Comparative plots showing percentage of oil recovered under base case and cumulative percentage recovered by base case and various injection options

Fig. 13 Comparative plots showing percentage of gas recovered under base case and cumulative percentage recovered by base case and various injection options

4. Conclusion

Comparative study on the application of three injection fluid options (SeW, WAG and SeWAG) in concurrent development of oil rim reservoir has been carried out. The study has shown that SeWAG has the highest recovery factor optimization effect on concurrent development of oil rim reservoir. The optimization effect was as a result of its combined good wetting ability the surfactant gives the reservoir rock, which subsequently causes reduction in contact angle between entrapped residual oil saturation in the pore spaces of reservoir rock and the CO₂ ability to cause oil swelling, viscosity reduction; thus, improves oil mobility into the production well. However, SeW and WAG injections do not have combined optimization effect as SeWAG; thus, their recovery factors optimization effect is lower compared to SeWAG injection in the concurrent development of oil rim reservoir.

This study has shown that more volume of oil and gas can be recovered in concurrent development of oil rim reservoir if the development is in two stages. The first stage is to commence natural depletion method. When the reservoir pressure is depleted, it is suitable to commence SeWAG injection for additional recoveries of oil and gas to have cumulative recoveries of oil and gas from both natural depletion and SeWAG injection in concurrent development of the oil rim reservoir.

Conflict of Interests

The authors declare that there is no conflict of interests regarding the publication of this paper.

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