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Evaluation of the use of Water Alternated Gas Injection for Enhanced Oil Recovery

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Abstract

Hydrocarbon can be naturally produced from underneath fractured sandstone when pressure can no longer force fluids to the surface facilities. A satisfactory recovery factor for this production was conducted through the cost-effective enhanced oil recovery (EOR) method. Water alternated gas (WAG) injection is a promising EOR technique that combines the advantages of waterflooding and gas injection to achieve better mobility control, improved sweep efficiency, and overall recovery from the given reservoir. Therefore, this study aims to investigate the relationship of a miscible WAG to a core flood model using numerical simulation techniques (Eclipse Reservoir Simulator – Black Oil Model Option). In this case, reservoir X consisting of three wells drilled 15 years after the initial forecast showed that production cannot be sustained by natural depletion. Furthermore, the optimal WAG ratio was selected with different simulation scenarios using oil recovery factors to perform 12 simulation runs and study the influence of the WAG cycle period. The most effective WAG cycle scenario was 90W-30G with an oil recovery factor of 0.54684 (54.68 %) and cumulative production of 14.987MMSTB. The 30W-90G produced the lowest oil recovery factor and cumulative production of 0.47468 (47.47%) and 12.996 MMSTB, respectively. Therefore, a higher water cycling period is required for better oil recovery. The recovery is also enhanced by lowering the rate of water to gas injection. The results showed that despite the predicted higher recovery factor, a lower WAG ratio indicated a potential of relatively low-pressure maintenance which can affect future recovery from the reservoir.

INTRODUCTION

Earlier application of a water-alternated gas (WAG) injection project as an EOR technique aimed to enhance sweeping efficiency during normal gas injection. However, in more recent times, the scope of this scheme has been broadened to incorporate pressure maintenance and improved oil recovery. WAG injection processes are often presented as an EOR technology to leverage the effect of gravity on continuous gas and water injections with a sweep efficiency up to 90%. Over the years, this scheme has been identified as being extremely promising. However, the chance of a WAG injection can be severely limited due to the apparent complexity associated with their designs. The several factors that contribute to the success of a WAG project are reservoir heterogeneity and stratification, availability and composition of injection gas, WAG ratio and cycling time, injection pattern, injection/production pressure and rate flow dispersion, and the time to initiate the process (Christensen et al., 2001; Heeremans et al., 2006; Zahoor et al., 2011). Faisal et al., (2009) and Torabi et al., (2010) stated that reservoir stratification and heterogeneity affect capillary pressure, relative permeability, and mobility ratios in an injection scheme. These factors further influence the displacement of the native fluids, and the extent is quite specific to a particular reservoir. Furthermore, Wu et al., (2004) showed that the presence of high permeability streaks causes channeling of the displacing solvent and reduces the storage and displacement efficiency. In WAG operation scenarios, this phenomenon controls the injection and sweep patterns in the flood to strongly influence the overall efficiency of the process.

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Another influencing factor that cannot be ignored is the choice of a WAG gas composition. It determines whether the WAG scheme will be miscible or immiscible at certain operational conditions (temperature and pressure) (Zahoor et al., 2011). The gas composition also has significant economic implications but it is better accounted for in the consideration of WAG ratio design. WAG ratio measures the ratio of the volume of water injected into the reservoir, and it is an optimization factor in recovery process (Chen et al., 2010). The optimal WAG ratio of reservoirs differs because the performance of the scheme depends on the number of combined factors such as permeability distribution, gravity segregation (which are influenced by fluid densities, viscosities, and reservoir flow rates), reservoir wettability, and the availability of the injection gas (Wu et al., 2004). A very high WAG ratio may lead to oil trapping by water blocking or insufficient solvent-oil contact, and in contrast, gas channeling may occur. Generally, the scheme can be entirely defeated resulting in a normal water or gas injection respectively. The cycling time is always considered using a prescribed rule of thumb during the design. However, the differences in various producing fields and some complex scenarios associated with the use of simulators to obtain the optimal cycling time in the WAG EOR mechanism (Pritchard & Nieman, 1992).

It has been observed that the injectivity of water and gas in regions of low and high permeability is controlled by WAG ratio and injection rates (Surguchev et al., 1992). Early gas breakthroughs are associated with wells at bottom-hole pressures far below the bubble point. The choice of the desired injection pattern (relative spacing of the wells) can be made for most fields after several simulations despite a "seemingly" rule of thumb that often recommends a 5-spot pattern (Zahoor et al., 2011; Darvishnezhad et al., 2010). The spacing of well and reservoir heterogeneity determines the phase dispersion of the various fluids present in the system. Generally, the industry-wide application of WAG has been motivated by better mobility control, the economic advantage of reduced injection gas volume through water substitution, improved residual oil recovery, and reservoir pressure maintenance. However, there has been a considerable hindrance to this EOR technique. These include controlling gas breakthrough as flood matures, injectivity loss, optimum slug size (typically 50% hydrocarbon pore volume injection), scale formation, corrosion issues, and the cost of implementing the WAG project (Drid & Tiab, 2004; Christensen et al., 2001; Reid et al., 2007). Furthermore, (Caudle & Dyes, 1958) presented a gas-water injection scheme aimed at improving miscible displacement by exploring ways to enhance sweep efficiency during the process as compared with the conventional techniques. The results showed that the reduction of mobility is a viable solution. In addition, the simultaneous injection of gas and water behind the miscible displacement possibly reduces the relative permeability as well as total mobility ratio since the gas zone is expected to exist between a miscible slug and the edge of the water. A comparative study showed that simultaneous WAG and continued gas injection gave 90% and 60% of sweep efficiency, respectively. Christensen et al., (2001) presented a review of field experience from the first reported WAG injection in the North Sea of Canada in 1957 by considering about 59 fields, consequently, the use of WAG injection around the world has increased.

Cobanoglu, (2001)designed different scenarios for injection quantity, cycle, as well as the number of produced and injected wells using the ECLIPSE 100 Simulator. The study compared immiscible gas and WAG injection methods in the Baty Kozluca field in Turkey. It was concluded that the immiscible gas injection technique considerably increased the field efficiency due to the inappropriate mobility ratio. Furthermore, WAG immiscible injection offers more efficiency compared with immiscible gas injection. Instefjord & Todnem, (2002) reported that the WAG injection technique increased oil production by 2 MMSTB during the injection period in the Gullfaks field. The technique increased displacement efficiency and reduced the percentage of produced water. Similarly, the Performance of WAG in a Stratified Reservoir presented by Drid & Tiab, (2004) to improve the sweep efficiency was achieved through sensitivity analysis. Samba & (Elsharafi, 2018) and Afzali et al., (2018) stated that WAG injection can improve microscopic sweep efficiency through better mobility control and extending the attic oil contact by water injection in a typical high permeable reservoir with gravity segregation effects. In addition, the residual oil saturation is less than the typical value resulting from either single-phase water or gas injection to identify the various problems associated with WAG processes. These include an early breakthrough in wells, reduced injectivity, corrosion, scale formation, and temperature differences of the injected phases.

The performance of a WAG project as an EOR technique is impacted by the reservoir characteristics and heterogeneity, rock and fluid properties, injection fluid composition, flood pattern, WAG ratio, relative permeability effects and flow dispersion, gravity segregation, and availability of quality and reliable laboratory and simulation data. Meanwhile, WAG injection is a mature EOR technique with many success stories both at pore and field-scale implementations (Afzali et al., 2018). The application of WAG schemes is possibly enhanced by modifying the liquid phase using Polymer assisted water injection (PAWAG) and Polymer alternating gas injection (PAG). It was also probably conducted in gas phase modification by

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applying Foam assisted water alternating gas injection (FAWAG) or water alternating high-pressure air injection (WAHPAI)) as well as in operating conditions by employing miscible or immiscible WAG. Since the processes are characterized by a strong cyclic hysteresis effect which is directly correlated from the pressure drop behavior between the three and two-phase water injection experiments, the use of restart option in Eclipse-100 should be performed (Alzayer & Sohrabi, 2018). Furthermore, the cyclic hysteresis essential at the core scale should be incorporated in full reservoir scale simulations to enhance performance prediction accuracy. Bhadran et al., (2019) showed that image processing techniques can be used to disperse saturated residual oil in the water wet pores after initial waterflooding for the continuous cycle of WAG injection.

Mechanistic numerical simulation also can be carried out to model previous WAG and foam-assisted chemical flooding core-flood experiments (Janssen et al., 2020). In addition, a 1-D model was built to obtain tomography scan data and assign varying porosity and permeability to each grid. Reduction of the gas phase relative permeability results in a better match for the WAG experiment as shown by the history matching. Abdullah & Hasan, (2021) studied a two-phase bonding imbibitions and drainage relative permeability model (Stone 1 and Stone 2) that were incorporated with a corresponding two-phase hysteresis model to obtain an optimal WAG ratio of 1:1 with a miscible WAG injection. The minimum miscibility pressure was reached at the shortest WAG cycle time of 180days which resulted in higher oil production. Several studies have been presented towards optimizing the performance of the WAG technique since the advent of EOR such as the use of evolutionary algorithms (Ferreira et al., 2018). These methods rely on the use of commercial reservoir simulators to investigate critical parameters associated with the WAG method of EOR (Algharaib et al., 2007; Shi et al., 2008; Mousavi Mirkalaei et al., 2011; Jiang et al., 2012). For the efficient design of the scheme, adequate evaluation of the effect of WAG ratio, water and gas injection rate, water and gas cycle period, field pressure on production rates and oil recovery factor is vital. Therefore, this study aims to evaluate the use of WAG injection in enhancing oil recovery for a reservoir in the Niger Delta.

MATERIAL AND METHODS

This study considers a 1-D reservoir model produced for 15 years using three wells. Prediction of future performance at different WAG ratios and cycling periods was made using a time step of 10 days over a 15-year production forecast with Schlumberger Eclipse 100 (Black Oil Model). Furthermore, the natural potential of the reservoir was previously simulated and the results showed the need to implement a WAG process with production. Twenty-one (21) simulation runs were executed for both case studies and cycle period sensitivity studies and the case definition is presented in Table 1

Table 1. Case Definition

S/N	Parameter	Description
1	Reservoir Type	Ordinary Black Oil Reservoir
2	Equation of State	Peng Robinson
3	Phases Present	Oil, water, and gas
4	Simulation Start Date	21st December 2020
5	Reservoir Model	Block Centered

Reservoir Description and Simulation Scenarios

The Reservoir X considered was a 12x1x1 uniformly gridded reservoir with cell dimensions, ΔX = 1000ft, ΔY = 1000ft and ΔZ = 75ft. It has two oil producers, OML-X1 and OML-X2, and a WAG injection well, ALPHA-01/02 located at (1,1), (12, 1), and (6, 1) respectively as shown in Figure1. The WAG project was implemented after the initial forecast showed that natural depletion cannot sustain production from the onset of the field's life. The optimal WAG ratio was selected using oil recovery factor criteria by using different simulation scenarios. In addition, the resulting WAG ratio was used to perform other simulation runs (12 simulations) and the influence of the WAG cycle period on oil recovery factor as well as cumulative production as shown in Table 2.

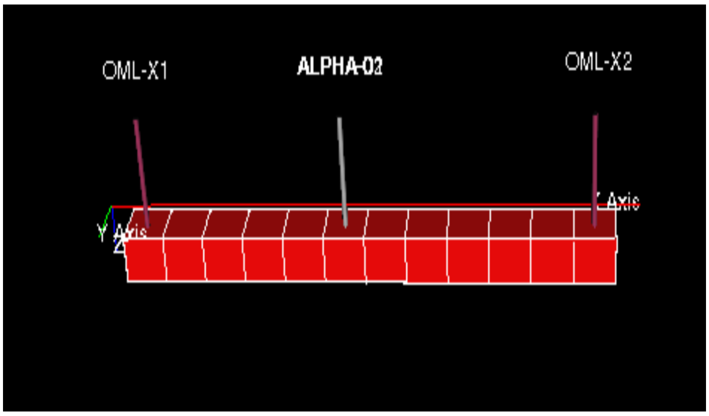

Figure1. 1-D Reservoir Grid Layout

Table 2. Base Case Sensitivity Studies of WAG Ratio

Base Case	WAG Ratio	Water Rate (STB/Day)	Gas Rate (Mscf/day)	Oil Recovery Factor
1	1:1	20000	20000	0.45781
2	1:2	20000	40000	0.48734
3	2:1	40000	20000	0.45781
4	1:3	20000	60000	0.50380
5	3:1	60000	20000	0.45781

The grid properties, geometry, and top surfaces of the case study reservoir are shown in Table 3

Table 3. Reservoir Grid Definitions

S/N	Property	Description/Unit
Grid type	Cartesian (Block Centered)	Ft
Grid Dimension	12x1x1	
Total Number of Cells	12	
PERMX	50	md
PERMY	50	md
PERMZ	5	md
Porosity	0.2	Fraction
DX	1000	Ft
DY	1000	Ft
DZ	75	Ft
Net to Gross Ratio	1	Dimensionless
Depth of Top Surfaces (TOPS)	8350	ft

The detailed well completion schedule and rate of injection and cycle days are presented in Table 4 and 5. The ALPHA-01 and ALPHA-02 are similar well used for the WAG project to represent the water and gas injection periods respectively. The ALPHA-01 was first opened for water injection for 180 days and later shut and converted to ALPHA-02 for gas injection. These processes were alternated over the total production period and repeated for five (5) WAG ratios at different cycling period.

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Table 4. Well Completion Summary

Location/Control Parameter	OML-X1	OML-X2	ALPHA-01 (Water Phase)	ALPHA-02 (Gas Phase)
i-location	1	12	6	6
j-location	1	1	1	1
k-upper	1	1	1	1
k-lower	1	1	1	1
Preferred Phase	OIL	OIL	WATER	GAS
Well type	Producer	Producer	Injector	Injector
Well Control Mode	BHP	BHP	WRAT/BHP	GRAT/BHP
Wellbore Radius	0.33ft	033ft	0.33ft	0.33ft

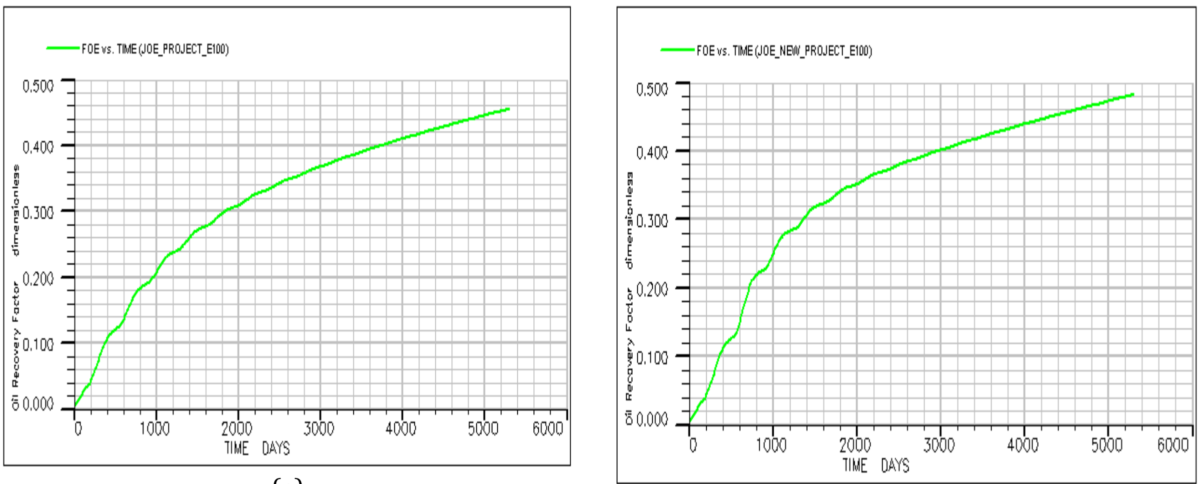
Table 5. Injection Well Allocation and Scheduling

TASK	ALPHA-01	ALPHA-02
RATE	20000STB/day	60000Mscf/day
WCYCLE	180days	180days
WELOPEN	21/12/2020	Shut
WELOPEN	Shut	18/05/2021

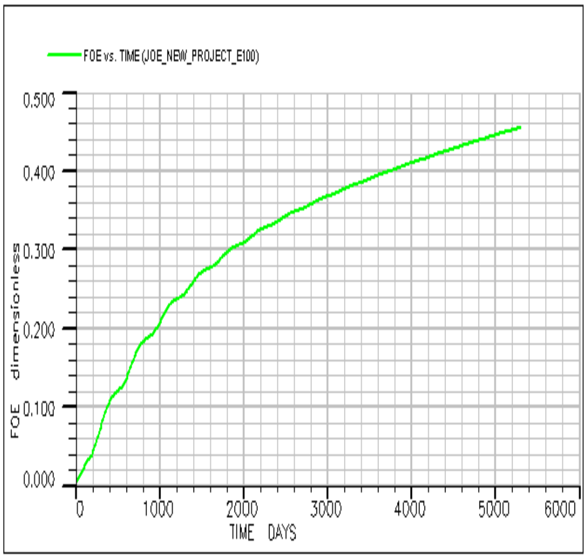
RESULTS AND DISCUSSION

The Effects of WAG Ratio on Oil Recovery

In this study, 5 different WAG ratios were simulated at base condition of an 180W-180G cycle period as presented in Table 5. The results showed that the lower the cycle ratio, the higher the oil recovery from the reservoir. At 1:3 (lowest) and 1:1 (highest ratio), the maximum oil recovery factor was predicted to be 0.50380 and 0.45781, respectively. The gas rate plays the most part in the predicted recovery factor especially injection at high rates. There was no remarkable increment in the oil recovery factor as shown in Table 5 despite increasing the water rates by 2-3 times while keeping the gas rate at 20000Mscf/day. The oil recovery factor or field oil efficiency(FOE) versus time is presented in Figure 2. The field oil efficiency or recovery factor yield the highest recovery factor at 1:3 WAG ratio of 0.50380. Meanwhile, 2:1 and 1:2 WAG ratio yields 0.45781 and 0.48734 in conformity with 0.439 for Miscible WAG of 2:1. This was higher than 0.348 for Miscible WAG of 1:2 as presented by Oladepo *et al.* (2017). The extrapolated future trend suggested that the maximum recovery factor obtainable at each WAG ratio does not exceed 0.6 (or 60%).



(a) (b)



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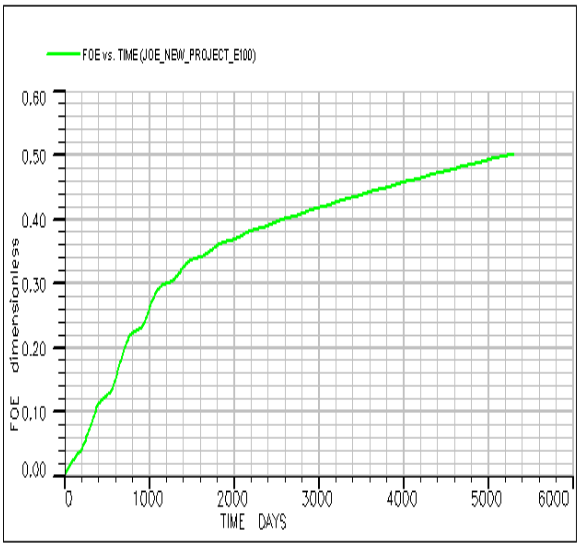

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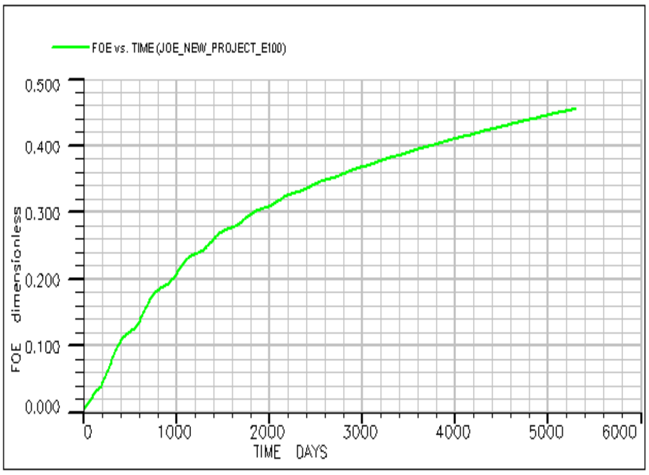

(e)

Figure 2.Oil Recovery Factor(RF) at (a)1:1 WAG Ratio; (b) 1:2 WAG Ratio; (c) 2:1 WAG Ratio; (d) 1:3 WAG Ratio; (e) 3:1 WAG Ratio

The results showed that the production of this field using only water or gas injection yields oil recovery factors of 0.17426 and 0.79662 as presented in Table 6. This identifies the great economic and technical prospects of a WAG technique. Furthermore, it reduces the required amount of gas to be injected and also provides better sweep efficiency than the ordinary waterflooding process.

Field Pressure and Oil Production Rates

Figure 3 showed the injection rates during the water-gas alternating processes and gas rates were observed to stabilize faster at a higher WAG ratio. This results in better sweep efficiency and reduced gas mobility as observed by (Sørbel, 2015). Figure 4 compared the oil production rates and the reservoir pressure profiles, and the significant disruption at the earlier stage of the field is an indication of how the reservoir is significantly impacted. Since the WAG ratio of 1:3 gave the highest recovery factor, therefore, higher gas to water injection rates is expected to yield a better oil recovery. However, the results in Figures 4(b and d) raise an important concern that can be associated with high gas-to-water injection rates. Gas and water injection rates relatively increase the challenge caused by pressure maintenance as shown by the fluctuations of the field pressure curve. Therefore, the long-prevailing issue of decline in early pressure associated with gas injection projects can defeat one of the primary motivations for the choice of a WAG scheme over normal gas injection.

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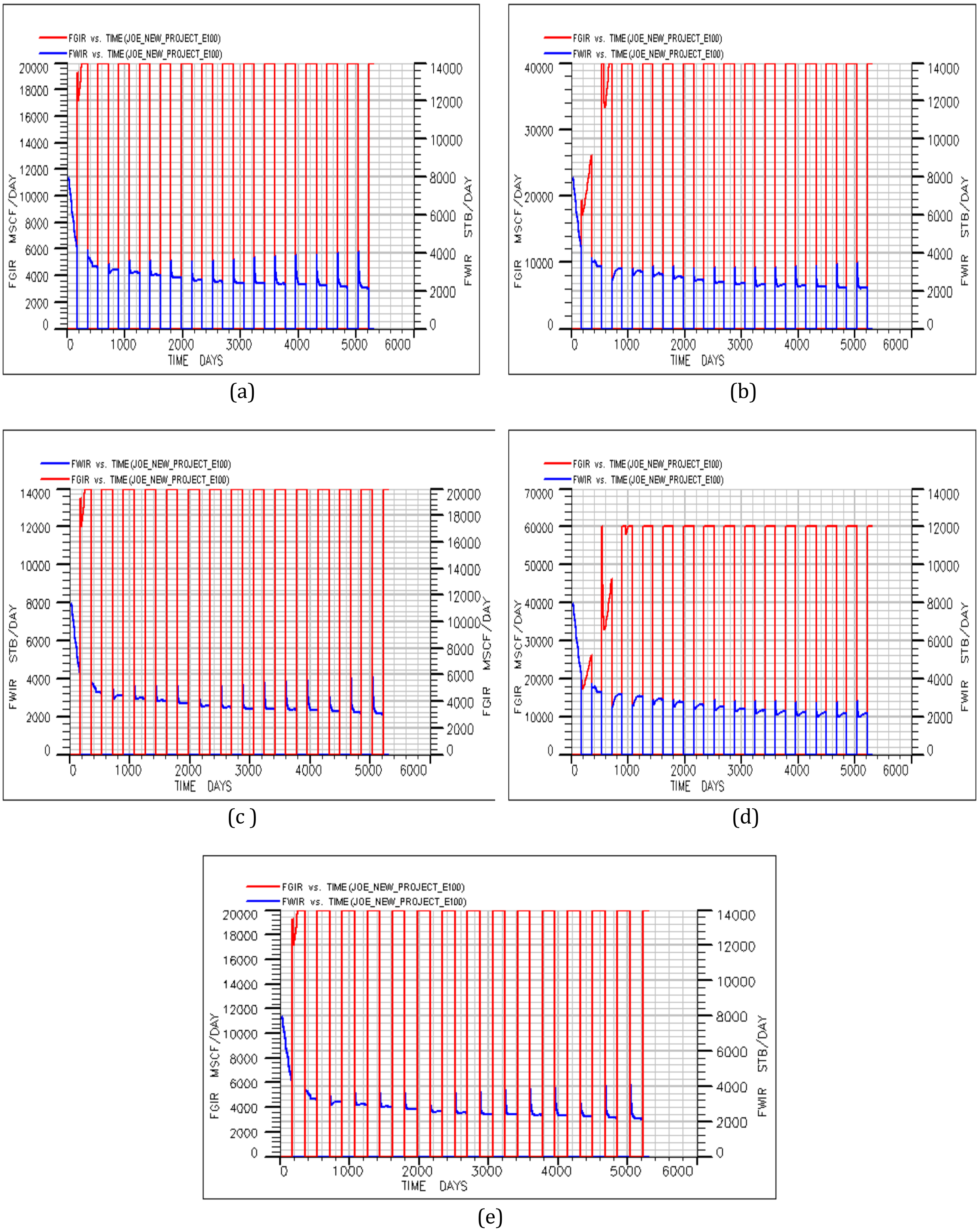

Figure 3. Field Gas Injection Rate(FGIR) and Field Water Injection Rate(FWIR)versus time at (a)1:1 WAG Ratio; (b) 1:2 WAG Ratio; (c) 2:1 WAG Ratio; (d) 1:3 WAG Ratio; (e) 3:1 WAG Ratio

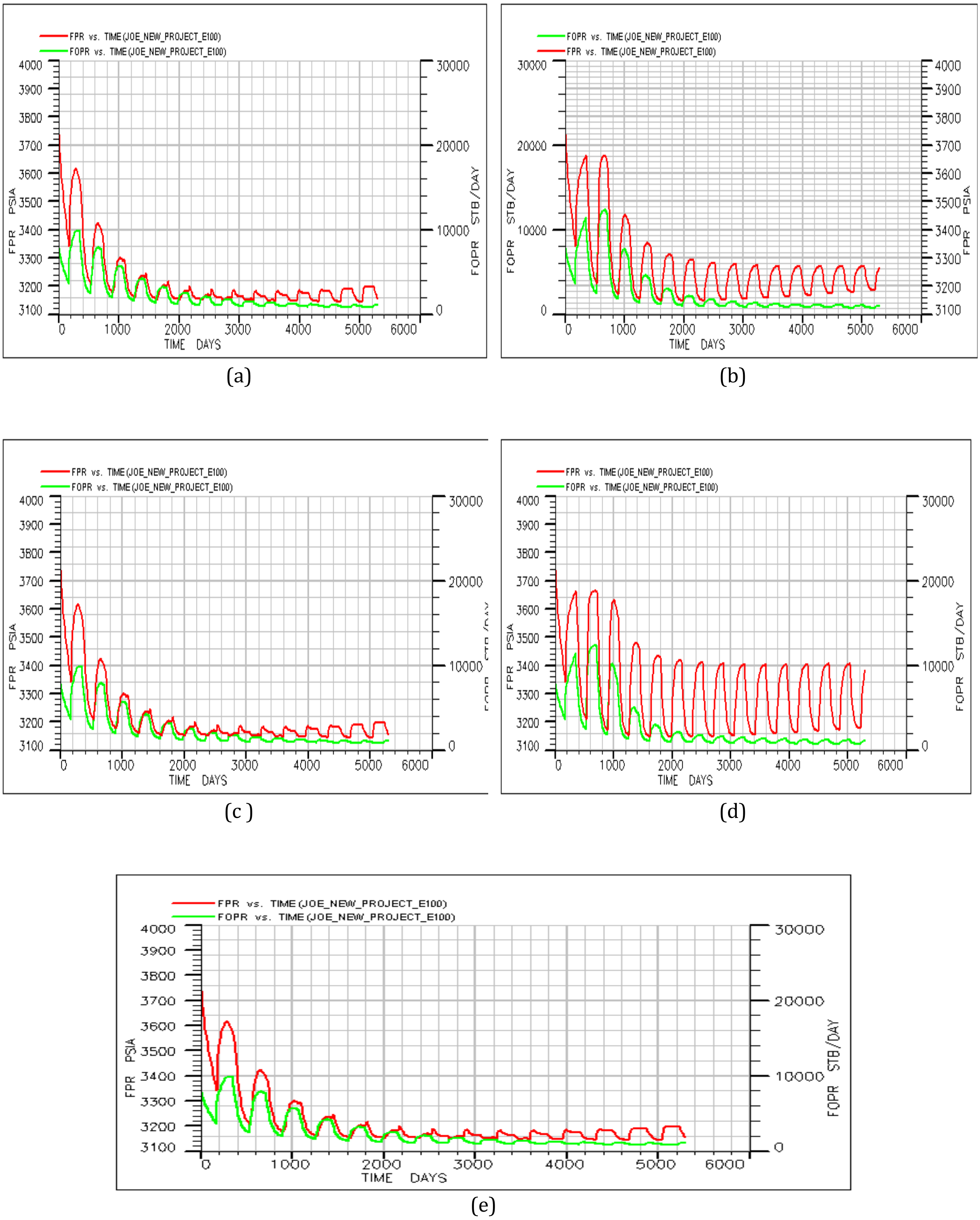

Figure 4. Field Oil Production Rate (FOPR)and Fied Pressure(FPR) versus time at (a)1:1 WAG Ratio; (b) 1:2 WAG Ratio; (c) 2:1 WAG Ratio; (d) 1:3 WAG Ratio; (e) 3:1 WAG Ratio

Mobility control is necessary to prevent early gas breakthroughs which is one of the primaries aims of most WAG processes. Economically, injecting at a WAG ratio of 1:2 may be recommended since the resulting recovery factor are quite comparable following a reduction in the required amount of gas when compared to the 1:3 ratio.

Field Gas Oil Ratio (FGOR) and Field Water Cut (FWCT)

Normally, the gas injection has a direct effect on the Gas Oil Ratio (GOR) while water injection essentially decides the water cut with time. The results presented in Figure 5 compared the field gas injection rates (FGIR) and the resulting field gas-oil ratio (FGOR). It showed that the reduction in WAG ratio (which

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implies higher gas injection rates) increases the produced gas-oil ratio, and this increment was not affected by the water injection rates. Therefore, the produced GOR remains constant regardless of the water injection rate during the water phase injection.

Similarly, the field water cut is solely controlled by the injection rates. There is a direct proportionality between the WAG ratio and the water cut which affirmed the results of (Oladepo David et al., 2017). The highest water cut was observed at a WAG ratio of 3:1. However, these observed values are nearly negligible and may not have serious issues with producing the reservoir at the current injection rates. Figure 6 showed the results of the ratio of field water injection rate (FWIR) and field water cut(FWCT).

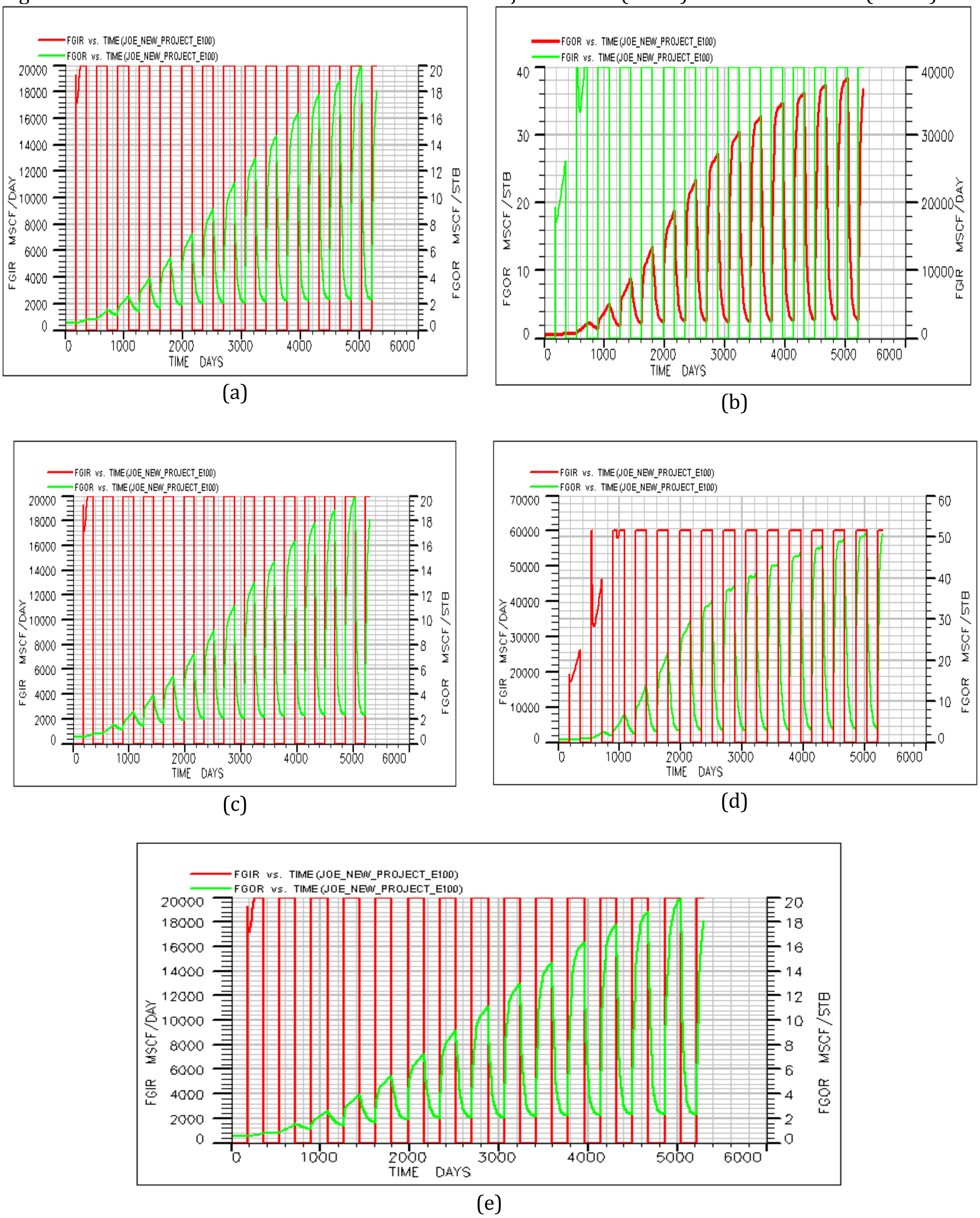

Figure 5. Field Gas Injection Rate(FGIR)and Fied Gas Oil Ratio(FGOR) versus time at (a)1:1 WAG Ratio; (b) 1:2 WAG Ratio; (c) 2:1 WAG Ratio; (d) 1:3 WAG Ratio; (e) 3:1 WAG Ratio

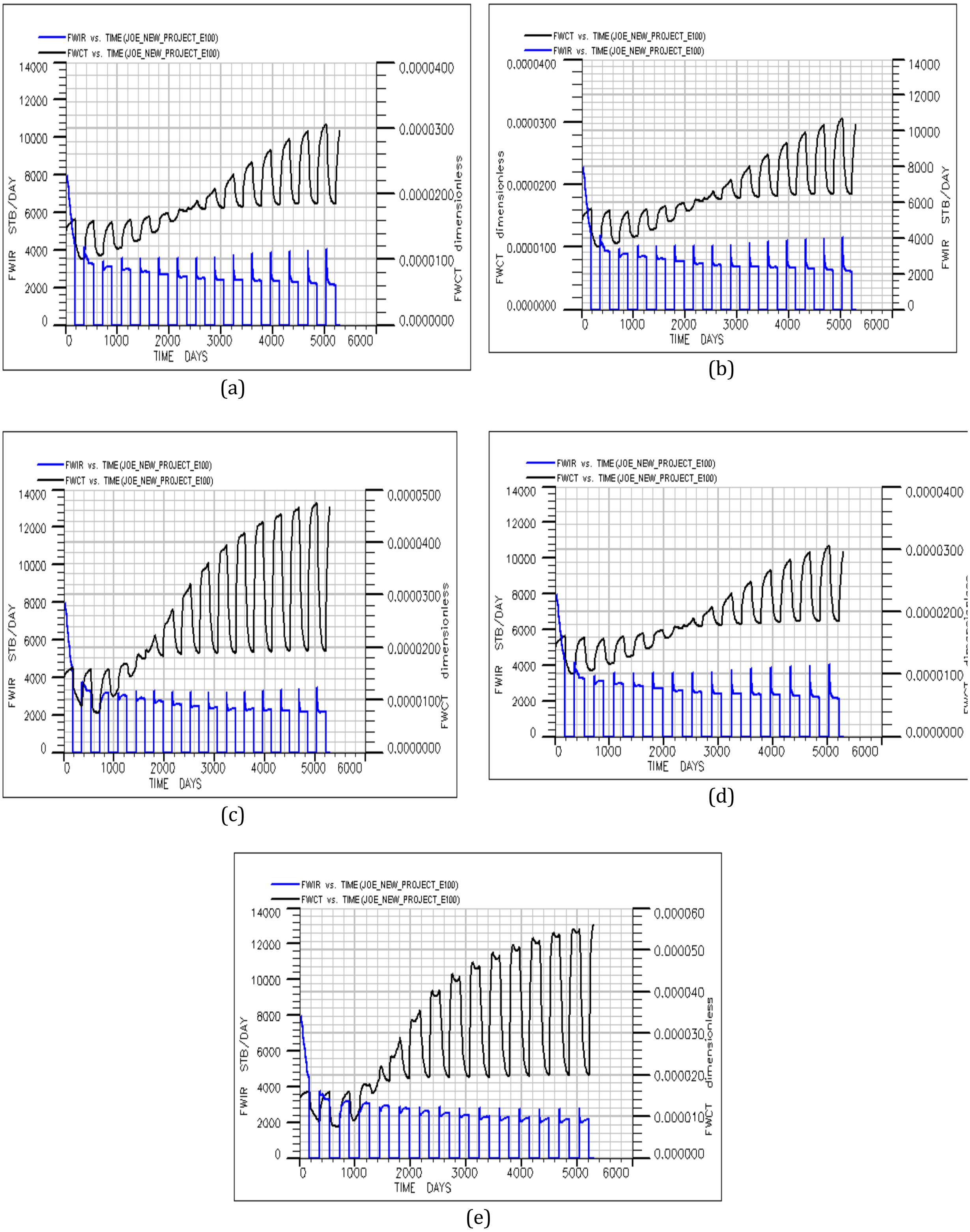

Figure 6. Field Water Injection Rate(FWIR)and Fied Water Cut(FWCT)) versus time at (a)1:1 WAG Ratio; (b) 1:2 WAG Ratio; (c) 2:1 WAG Ratio; (d) 1:3 WAG Ratio; (e) 3:1 WAG Ratio

Optimal WAG Cycle for Higher Recovery Factor and Cumulative Oil Production

The WAG ratio 1:3 gave the highest oil recovery potential at a base case of 180W-180G, and it was used to study the effect of different WAG cycles on the oil recovery factor as well as the cumulative oil production. 90W-30G gave the optimal cycle period with an oil recovery factor of 0.54684 and cumulative production of 1497300STB. Furthermore, 30W-90G gave the lowest oil recovery factor and cumulative production of 0.47468 and 129995800STB. Therefore, a longer water injection period has better recovery for all

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alternating cycling periods as shown in Table 6 as well as Figures 7 and 8. The high oil recovery factor obtained for the high water to low gas cycle period was consistent with the findings of Han (2015).

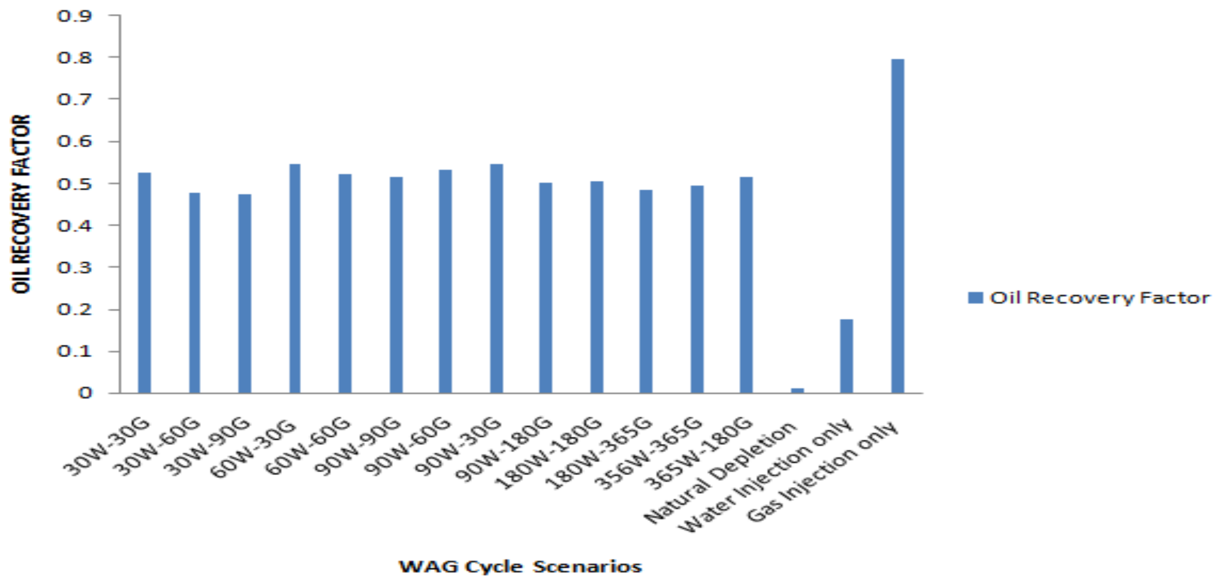

Figure 7. Different WAG Cycle Periods (days) and the Oil Recovery Factor

Table 6. The Influence of WAG Cycle on Oil Recovery Factor and Cumulative Oil Production

WAG Cycle Scenarios	Cycle period in days	Oil Recovery Factor	Cumulative Oil Production (STB)
1	30W-30G	0.52405	14379700
2	30W-60G	0.47679	13113900
3	30W-90G	0.47468	12995800
4	60W-30G	0.54430	14919800
5	60W-60G	0.52152	14312200
6	90W-90G	0.51646	14177200
7	90W-60G	0.53165	14649800
8	90W-30G	0.54684	14987300
9	90W-180G	0.50000	13704600
10*(Base Case)	180W-180G	0.50380	13808755
11	180W-365G	0.48523	13350200
12	356W-365G	0.49578	13586500
13	365W-180G	0.51646	14177200
14	Natural Depletion (no WAG Process)	0.00877	241772
15	Water Injection only at Rate = 20000STB/DAY	0.17426	4831220
16	Gas Injection only at Rate = 60000Mscf/day	0.79662	21898700

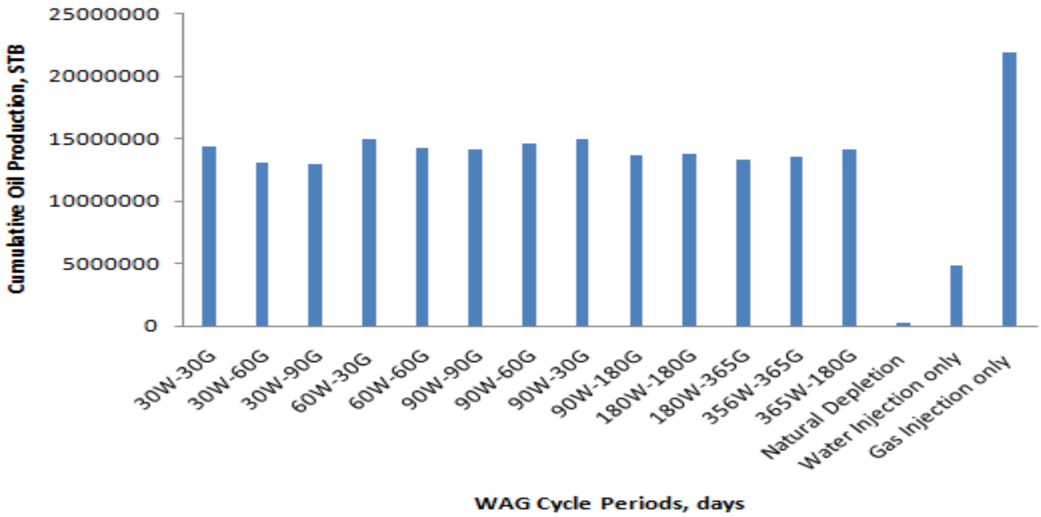

Figure 8. Different WAG Cycle Periods (days) and the Cumulative Oil Production

CONCLUSION

This study investigated and evaluated the use of WAG in increasing cumulative production of oil recovery. It was concluded that the WAG ratio impacts the overall oil recovery with the optimal ratio ranging from 1:2 to 1:3. The WAG cycling period of water relative to gas also impacts the oil recovery factor and the cumulative production. Furthermore, longer water injection ensures optimal recovery from the reservoir, and a rule of thumb for the WAG cycle period can be set at 60W/30G – 90W/30G for the reservoir. High gas injection rates caused more pressure drops and can also lead to mobility challenges and early gas breakthroughs.

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