Effect of water and gas injection schemes on synthetic oil rim models

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Abstract

Oil recovery in oil rim reservoirs is usually affected by reservoir and operational parameters. An experiment was designed to develop various types of oil rims with a broader range of uncertainties. Mensuration analysis was used to create the basic grid designs, while the Eclipse software was used to incorporate pressure, volume and temperature and reservoir fluid properties to create a black oil model for oil rims. The reservoir models were conditioned to a simultaneous production scheme through which a response surface model was generated to represent oil recovery for all the models. The models were later classified into drive mechanisms based on the results from the Pareto analysis. Various secondary injection schemes were carried out based on reservoir geometry to investigate their response on oil recovery. Results show that for single injection schemes, oil recovery from water down-dip (6.5%) and water up-dip (4.37%) was higher than gas scheme injection for reservoir model 10. Oil recovered from up-dip and down-dip water injection (7.1%) was higher than gas up-dip and down-dip injection (0.03%) for reservoir model 10, and for the same model, an oil recovery of 7.7% and 5.63% was recorded for gas up-dip and water down-dip injection and gas down-dip and water up-dip injection, respectively. The final analysis shows that there is an appreciable increase in oil recovery when injection rates are increased as seen in water down-dip and up-dip injection with 15.43% recovery for reservoir model 10.

Keywords Oil rim · Design of experiment · Water and gas injection · Response surface model

Abbreviations

OCIP	Oil currently in place
IGV	Initial gas volume
GCIP	Gas currently in place
BHP	Bottom hole pressure
K_{rw}	Water relative permeability
DOE	Design of experiment
PB	Placket–Burman
Stb	Stock tank barrel
GOC	Gas–oil contact
HWL	Horizontal well length
Qo	Oil flow rate
IOV	Initial oil volume
$*R_{si}$	GOR control
HGOC	Perforations with respect to the GOC
K_x, K_y	Horizontal permeability
M-fac	Gas cap size
RSM	Response surface model

Introduction

Ibunkun (2011) documented the factors affecting the performance of oil rims. These factors did not incorporate major operational and reservoir parameters, and the estimation of oil recovery is based on sensitivity analysis. Oil rim recovery has been documented by few authors such as Iyare and Marcelle-De Silva (2012) by initiating sensitivity analysis on important uncertainties that affect oil rim productivity. The results obtained from these methods are from a randomly selected production scheme and static uncertainties. Sensitivity analysis on each of these properties will have an effect on oil and gas recovery. For example, using an extended horizontal well is viable for increase in oil and gas recovery as described by Olabode and Egeonu (2017). Analyzing productivity in oil rims has mostly been based on insufficient data, uncertainties and adequate design of models in estimating the overall oil recovery and selection of proper secondary injection scheme. The effects of these properties on recoveries can be well established by simulating results obtained from design of experiment, and thus, a response surface model generated (Wyne 2005) developed a screening criterion for oil rims based only on the gas cap factor and

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height of oil column irrespective of the oil recovery, while Osoro et al. (2005) estimated oil recovery efficiencies in oil rims only as a function of the height of oil column. Lawal et al. (2010) identified that previous simulation studies on oil rim reservoirs showed no dependency between recovery factor and oil viscosity, oil formation volume factor, ratio of initial volumes of gas caps and oil, ignoring rock and fluid properties.

To adequately capture all important parameters that affect oil rim productivity, it is best to design an experiment to fairly assess all uncertainties, thus creating a limited number of required models from such parameters. Experimental designs were used by Olamigoke and Peacock (2012) to suggest and validate effective screening models for optimizing oil and gas recovery in oil rim reservoirs. Kabir et al. (2002) and Obah et al. (2012) both designed an experiment with limited uncertainties to develop a response surface model to estimate oil recovery in oil rim reservoirs. Although their work did not include a Pareto analysis, the higher the number of these parameters, the more effective the Pareto analysis of significant parameters. The related shortfalls of these previous studies are that certain operational and underlying factors some of which are mentioned by Olamigoke and Peacock (2012) are disregarded. This results to an erroneous derivation of a RSM which cannot represent or be used to estimate oil and/or gas recovery (depending on the production scheme) from oil rim reservoirs. It is important to estimate oil recovery from production plans before initiating recovery schemes. In doing so, it is paramount to take into full consideration all major parameters that affect oil recovery. For example, most researches have excluded the effect of reservoir structure such as angle of dip even in their sensitivity analysis on estimating recovery factor.

Masoudi (2013) discussed the applied fundamentals, critical elements and proven practices to maximize the hydrocarbon recovery in successful and integrated oil rim developments. His work covers the reliable volumetric assessment and development concept (i.e., sequential, concurrent, etc.) and robust and proactive reservoir management/monitoring policy to advise on depletion strategies and production to control the coning and cusping of water and gas. Cosmo and Fatoke (2004) established the viability of concurrent strategy of production in oil rims with large gas caps and developed an inadequate matrix of development strategy based on oil rim thickness and gas cap size thus neglecting other important parameters.

It is important to know the nature of the dominant reservoir drive in making predictions on factors such as well placements and injection policies to be initiated. The presiding factors affecting oil reservoirs are usually optimized to predict when coning is likely to occur Olabode et al. (2018c). Due to the nature of oil rim reservoirs, these best production practices will yield low oil recovery Olabode et al (2019).

Most simulation studies on oil rims are usually based on a gas cap-driven reservoir, and this can evidently determine the type of injection schemes and oil recovery outcome.

Secondary injection schemes are initiated to keep the force balance and place the production wells within the reach of the oil rim to increase oil recovery. Signifying the active drive mechanism is necessary for oil rim classifications and placement of injection wells. The usual assumption is that most oil rims are gas cap driven, and this has affected oil recovery under water or gas injection schemes.

Razak et al. (2010) have duly noted that understanding of this force balances in the reservoir will result in better optimization of the reservoir oil and gas production and to plan a selective secondary and enhanced oil recovery mechanism.

Ezzem et al. (2010) initiated fencing and peripheral injection and also combined peripheral and fencing injection due to declining pressure across the reservoir. They concluded that peripheral water injection increases pressure support and vertical sweep efficiencies, whereas fencing water injection will supplement the produced gas injection at the gas cap to suppress oil rim movement toward the gas cap. Due to the significant oil left behind, the authors implemented a simultaneous injection of gas down-dip and water up-dip to sweep oil laterally due to gravity segregation and improve oil recovery.

Onyeukwu et al. (2012) comparatively concluded that in terms of incremental recovery, the benefits of water injection outweigh gas injection for a weak aquifer because the large gas cap supplies most of the pressure support making pressure maintenance by gas injection unnecessary, especially if there is an effective gas–oil ratio (GOR) constraint in place. Their work included reservoir simulation on oil rim development with sensitivities on permeability anisotropy, GOR policy, aquifer strength and oil rim thickness during water and gas injection. Their simulation study shows that simultaneous gas and water injection can improve oil rim recoveries by 15% of oil initially in place.

Wafaa et al. (2009) in designing a simultaneous water alternating gas process for optimizing oil recovery concluded that the performance of the modified simultaneous water alternating gas (SWAG) scheme is sensitive to the water and gas injection rates and cases with high water alternating gas (WAG) injection resulted in better fractional oil recovery than cases with low water and gas injection rates.

Thang et al. (2010) did an extensive enhanced oil recovery on an oil rim in the Samarang oil field by developing injector wells at up-dip and down-dip locations of the reservoir. They developed singular and simultaneous case scenarios of down-dip and up-dip injection of gas and water. Their result showed that simultaneous up-dip water and down-dip gas injection gave the highest recovery compared to other injection schemes. The scheme improved the sweep efficiency of the lower section on the inner part of the oil rim

with the downward movement of water and subsequently at the same time increased the sweep efficiency of the upper section of the outer part of the oil rim with the upward movement of gas injected.

The challenges faced during the simulation studies of oil rims are mostly related to gas cap-driven reservoir. The classifications of oil rims will show an estimate of oil recovery from different secondary injection schemes based on the reservoir drive. The creation of oil rim models via a design of experiments on reservoir geometry, reservoir, fluid and operational properties from the literature has helped to create models for proper classifications and estimating oil recovery under varying production and injection schemes.

This paper incorporates a wider range of uncertainties that affect productivity of oil rims into a design to create oil rim models with different reservoir and operational properties. These models are developed into reservoir models by integrating them with solution, grid and PVT properties using the Eclipse black oil simulator option. Current depletion policies were analyzed for the best production option, and the models are classified based on reservoir drive size. Injection policies of water and gas were initiated with respect to reservoir geometry to ascertain how each of these models under their categorization behaves as regards to oil recovery. This choice helps to determine the possibilities of oil recovery for oil rim reservoirs with similar properties to these models and predict their outcome under various injection schemes.

Methodology

Olabode et al. (2018a) designed an experiment from identified and important oil rim uncertainties from the literature using a two-level Placket–Burman design of experiment (DOE). Fifteen identified parameters were used to generate 18 oil rim reservoir models. The description of the parameters and values is shown in Table 1. Table 2 describes the spatial arrangement of the uncertainties.

Simulation grid design

To create the reservoir geometry, a box model was implemented to show three various dipping degrees that may be exhibited in a thin oil rim reservoir. Our datum height was assumed to be 8500 ft. and slanted depth to TOPS faces 4000 ft. This makes the sizes of each cell in x - and y -directions 200 ft. each, i.e., from $20 \times 20 \times 41$. It was assumed that the reservoir was originally a box which later slanted in the x -direction to account for a dipping reservoir geometry and that the base of the box also took the same shape. This means the box dipped inward in the x -direction from the

Table 1 Oil rim uncertainties

Uncertainties		Units	Low – 1	Mid 0	High 1
a	Dip	°	1°	4	6
b	Gas wetness	stb/Mscf	0.006	0.03	0.04
c	Oil column height (H_o)	feet	20	40	70
d	M -fac		0.7	3	6
e	Aqfac		0.7	3	6
f	K_x, K_y	mD	35	350	3500
g	K_v/K_h		0.001	0.01	0.1
h	Wellbore diameter	feet	0.35	0.45	0.55
i	Oil density	lb/ft ³	37	42	47
j	HGOC	feet	0.25	0.45	0.6
k	HWL	feet	1200	1500	1800
l	Oil rate	stb/day	1200	2200	3500
m	Krw		0.2	0.35	0.6
n	GOR control ($*R_{st}$)		2.5	5	7.5
o	BHP	psia	1500	1800	2200

surface and dipped outward also in the x -direction from the base thus, making both assumed gas cap and aquifer volumes which are obviously at the surface and base have the same dip angles.

So let us take a case of dip angle 1°. The length of the reservoir in the x -direction increases downwards in 20 places with respect to the datum depth of 8500 ft. These increases are in the order of 1° in the x -direction (i.e., $4000 \times \sin 1^\circ$) (Figure 1). The resulting value was divided by the number of cells in the x -direction and then added to subsequent values that started with the datum depth.

While the height of the oil volume is the height of the oil rim, the volume of oil was estimated by calculating the volume of a cube, while the gas and water volumes were estimated from the m -fac and aqfac, respectively, which are in ratios with the volume of the oil column (Fig. 2).

Naturally, since gas region starts from the top of the box, the slanted part of the box was also coined out to be part of gas volume, and this was calculated by estimating the volume of the triangle. The volume of the triangle (if larger) was subtracted from the volume of gas and divided by the area of the box to get the original GOC height. (This height was subsequently subtracted from the height of the triangle.) The WOC is estimated by adding the height of oil column to the GOC. The total height in the z -direction is thus derived and divided accordingly to the heights estimated for the gas, water and oil zones. This process is carried out for the 18 simulation runs.

*Note: volume of gas is subtracted from volume of triangle (if volume of triangle is smaller), and the resulting height is added to the height of the triangle.

Table 2 Spatial arrangement of oil rim uncertainties

Reservoir models	a	b	c	d	e	f	g	h	i	j	k	l	m	n	o
Reservoir 1	6	0.04	70	6	6	3500	0.1	0.55	47	0.6	1800	3500	0.6	7.5	2200
Reservoir 2	1	0.04	20	6	0.7	3500	0.001	0.55	37	0.6	1200	3500	0.2	7.5	1500
Reservoir 3	6	0.006	20	6	6	35	0.001	0.55	47	0.25	1200	3500	0.6	2.5	1500
Reservoir 4	1	0.006	70	6	0.7	35	0.1	0.55	37	0.25	1800	3500	0.2	2.5	2200
Reservoir 5	6	0.04	70	0.7	0.7	35	0.001	0.55	47	0.6	1800	1200	0.2	2.5	1500
Reservoir 6	1	0.04	20	0.7	6	35	0.1	0.55	37	0.6	1200	1200	0.6	2.5	2200
Reservoir 7	6	0.006	20	0.7	0.7	3500	0.1	0.55	47	0.25	1200	1200	0.2	7.5	2200
Reservoir 8	1	0.006	70	0.7	6	3500	0.001	0.55	37	0.25	1800	1200	0.6	7.5	1500
Reservoir 9	6	0.04	70	6	6	3500	0.1	0.35	37	0.25	1200	1200	0.2	2.5	1500
Reservoir 10	1	0.04	20	6	0.7	3500	0.001	0.35	47	0.25	1800	1200	0.6	2.5	2200
Reservoir 11	6	0.006	20	6	6	35	0.001	0.35	37	0.6	1800	1200	0.2	7.5	2200
Reservoir 12	1	0.006	70	6	0.7	35	0.1	0.35	47	0.6	1200	1200	0.6	7.5	1500
Reservoir 13	6	0.04	70	0.7	0.7	35	0.001	0.35	37	0.25	1200	3500	0.6	7.5	2200
Reservoir 14	1	0.04	20	0.7	6	35	0.1	0.35	47	0.25	1800	3500	0.2	7.5	1500
Reservoir 15	6	0.006	20	0.7	0.7	3500	0.1	0.35	37	0.6	1800	3500	0.6	2.5	1500
Reservoir 16	1	0.006	70	0.7	6	3500	0.001	0.35	47	0.6	1200	3500	0.2	2.5	2200
Reservoir 17	1	0.006	20	0.7	0.7	35	0.001	0.35	37	0.25	1200	1200	0.2	2.5	1500
Reservoir 18	4	0.03	40	3	3	350	0.01	0.45	42	0.45	1500	2200	0.35	5	1800

Fig. 1 Rough sketch of grid design

Steps to grid model design

Step 1 $h = 4000 * \sin 1^\circ = 69.8096$

Step 2 $b = 4000 * \cos 1^\circ = 3999.4$

Step 3 assumed oil volume = $4000 * 4000 * 20 = 320 * 10^6 \text{ ft}^3$

Step 4 volume of triangular section = $\frac{1}{2} * b * h * 4000$,
 $\dots = \frac{1}{2} * 3999.4 * 69.8096 * 4000 = 558.4 * 10^6 \text{ ft}^3$

Step 5 volume of gas ($m\text{-fac} = 0.7$) = $0.7 * 320 * 10^6 = 224 * 10^6 \text{ ft}^3$

Step 6 volume of water ($aq\text{fac} = 6$) = $6 * 320 * 10^6 = 1920 * 10^6 \text{ ft}^3$

Step 7 $\frac{(558.4 - 224) * 10^6}{4000 * 4000} = 23.89$

Step 8 total gas height = $69.81 + 23.89 = 93.70 \text{ ft}$.

Step 9 GOC = $8500 + 93.70 = 8953.70 \text{ ft}$

Step 10 WOC = $8953.70 + 20 = 8613.70 \text{ ft}$ (assume $H_o = 20 \text{ ft}$)

Step 11 total Z = $69.81 + 69.81 + 20 + 23.9 + 106 = 289.51 \text{ ft}$
 (where $H_o = 20$, gas cap height = $69.81 + 23.9$, aquifer height = $106 + 23.9$)

Step 12 gas: $93.7 \text{ ft} \dots 10 \text{ cells} \dots 9.37 \text{ ft each}$,

oil: $20 \text{ ft} \dots 5 \text{ cells} \dots 4 \text{ ft each}$,

water: $175.8 \text{ ft} \dots 10 \text{ cells} \dots 17.58 \text{ ft each}$

Fluid (PVT) modeling

The fluid properties of interest include solution gas–oil ratio (GOR) R_s , oil–gas ratio (OGR), oil formation volume factor B_o , gas formation volume factor B_g , oil viscosity μ_o , gas viscosity μ_g , oil gravity γ_{API} and gas gravity, γ_g .

In the absence of laboratory PVT report, the PVT model for the reservoir was built using correlation in the PVT module in *Eclipse*® Office (black oil) and can be viewed in “Appendix.” The fluid properties modeled include gas formation volume factor, gas viscosity, water formation volume factor, water viscosity and water compressibility. The

Fig. 2 Recovery factor and estimates for models 13 and 16 from development strategy for thin oil rim models

fluid property data also have a close resemblance to what is obtainable in a normal thin oil rim reservoir. Figure 3 shows the initial fluid distributions and saturations for reservoir model 3 after initialization of rock and fluid properties. The figure also shows the oil rim placement and position with the overlying gas cap and underlying aquifer.

Production plan

To select the best depletion strategy, four scenarios were initiated described by Masoudi (2013). Two wells (for gas and oil production) are initiated for simultaneous production and the oil well converted to a gas well and recompleted in the gas region during the gas cap blowdown. The total production period was 10,000 days. The production period for sequential strategy is divided into two halves. The first

5000 days are for oil production, then the oil wells are shut while the last 5000 days will be for gas production; however, the cyclic or swing strategy alternated oil and gas production every 2500 days. Oil production rates are maintained at 1500 stb/day, and the gas cap off-take rates were 5% of gas initially in place. Figure 2 shows oil recovery for reservoir model 13, while Table 3 is the summary of oil recovery from the depletion strategies. Figure 2 shows that gas production will not jeopardize oil production under a concurrent strategy, which is the best policy to adopt for the models.

The Pareto principle maintaining that 80% of the output in a given situation or system is produced by 20% of the input is applied on the parameters to arrange them according to their significance or effectiveness to oil recovery. This helps to sort parameters from least to most significant effects on oil recovery. By drawing a line from the cumulative relative frequency axis at the 80% point to the graph

Fig. 3 Initial fluids in place and fluids saturation

Table 3 Oil recoveries from production strategies

Models	Oil recoveries from production strategies							
	Concurrent		Swing		Sequential		Gas cap blow down	
	RF (%)	Oil (stb)	RF (%)	Oil (stb)	RF (%)	Oil (stb)	RF (%)	Oil (stb)
Resv. model 3	22	1,222,785	22.0	1,225,172	22	1,224,983	21.3	1,186,644
Resv. model 8	5.1	1,208,875	1.51	354,253	1.5	349,770	4.9	1,191,054
Resv. model 13	6.7	1,136,245	4.59	783,493	4.6	783,318	5.9	1,009,297
Resv. model 16	6.5	1,499,402	1.55	358,718	1.5	355,055	4.9	1,142,099

Fig. 4 Pareto analysis of oil recovery variables

(Fig. 4), the significant parameters are well defined on the left-hand side of the arrow and also analyzed by Olabode et al. (2018a). Table 4 shows the oil and gas recoveries and oil currently in place after a concurrent production.

$$\begin{aligned}
 \text{Oil recovery factor} = & 11.4465 + 12.0662 * (x_1) + 17.3848 * (x_2) - 42.522 * (x_3) \\
 & + 47.9824 * (x_4) - 3.3584 * (x_5) + 34.9484 * (x_6) - 26.64 * (x_7) \\
 & + 0.3896 * (x_8) + 45.8114 * (x_9) - 27.632 * (x_{10}) - 14.216 * (x_{11}) \\
 & - 21.052 * (x_{12}) + 11.2064 * (x_{13}) - 17.07 * (x_{14}) - 6.0624 * (x_{15})
 \end{aligned} \quad (1)$$

Table 4 Concurrent production results

Oil production profile						Gas production profile				
Reservoir no.	Oil (stb)	IOV (Mstb)	RF (%)	OCIP (Mstb)	NFA	IGV (Mscf)	CUMM. PROD. (Mscf)	RF (%)	GCIP (Mscf)	NFA
Reservoir 3	1,222,449	5,561.6	22	4339	3995	315,410	203,742	64.6	111,668	3960
Reservoir 4	299,295	28,071	1	27,773	1609	330,684	50,000	15.1	280,684	1410
Reservoir 5	1,859,613	16,267	11	14,408	6204	96,761	63,316	65.4	33,445	6000
Reservoir 6	316,218	4690	7	4374	6000	62,184	28,892	46.5	33,292	6000
Reservoir 7	914,593	5750	16	4836	740	412,231	152,432	37.0	259,799	740
Reservoir 9	10,750,810	60,981	18	50,230	8672	1,009,138	620,356	61.5	388,782	8660
Reservoir 10	1,284,098	4542	28	3258	1069	122,448	49,020	40.0	73,428	1069
Reservoir 14	248,143	2878	9	2630	270	20,356	12,944	63.6	7412	542

$$\begin{aligned}
 \text{Gas recovery factor} = & 49.71483 - 12.8896.1 * (x_1) + 27.9174 * (x_2) - 13.1532 * (H_o) \\
 & + 3.426585 * (x_4) + 27.20964 * (x_5) - 6.14772 * (x_6) - 15.619075 * (x_7) \\
 & - 5.44819 * (x_8) - 23.0930 * (x_9) + 26.60462 * (x_{10}) - 16.3405 * (x_{11}) \\
 & - 16.3765 * (x_{12}) + 36.9368 * (x_{13}) + 15.1330 * (x_{14}) - 85.3602 * (x_{15})
 \end{aligned} \quad (2)$$

where

$$\begin{aligned}
 x_1 = \text{dip}, \quad x_2 = \text{OGR}, \quad x_3 = H_o, \quad x_4 = m\text{-factor}, \quad x_5 = \text{aqfac}, \\
 x_6 = K_x, K_y, \quad x_7 = \frac{K_v}{K_h}, \quad x_8 = \text{wellbore diameter}, \quad x_9 = \text{oil density}, \\
 x_{10} = \text{HGOC}, \quad x_{11} = \text{HWL}, \quad x_{12} = \text{oil rate}, \quad x_{13} = K_{rw}, \quad x_{14} = \text{GOR}, \quad x_{15} = \text{BHP}
 \end{aligned}$$

In effecting aquifer into the model, a linear numerical aquifer was defined by the model. The properties of the aquifer region were estimated from the grid blocks in the simulation runs. The strength of the aquifer can be determined by varying the aquifer length. The injection schemes commenced at the time step where there was a significant drop in production rate. The producer wells were confined to oil production to effectively estimate incremental oil recovery. The water injection rate was at 5000 stb/day, while gas injection rate was 500 Mscf/day. These are stabilized and optimized injection rates for all the models. Improved oil recovery can be achieved higher water and gas injection rates as described by Wafaa et al. (2009). Five secondary injection schemes of gas and water will be initiated with respect to the reservoir geometry as described in Table 6.

Cases 3 and 4 under phase 2 are merged for effective comparative analysis. The same goes for cases 5 and 6. The results are basically on a comparative analysis of oil recovery from these injection patterns.

Table 5 Classification of oil rim models

Reservoir type	Simulation models
Big gas cap and big aquifer	3 and 9
Big gas cap and small aquifer	4 and 10
Small gas cap and big aquifer	6 and 14
Small gas cap and small aquifer	5 and 7

Table 6 Secondary case scenarios

Phase 1 injection	Phase 2 injection	Phase 3 injection
Up-dip injections (water and gas) (case 1)	Gas up-dip and water down-dip (case 3) Gas down-dip and water up-dip (case 4)	Increasing injection gas and water injection rates for phase 1 (case 7)
Down-dip injection (water and gas) (case 2)	Gas up-dip and gas down-dip (case 5) Water up-dip and water down-dip (case 6)	

Results

Phase 1: Up-dip injection (Case 1)

The injector wells were initiated with respect to the reservoir geometry which is indicated by the Pareto analysis as a significant parameter. Table 7 shows the incremental oil recovery values from up-dip injections of either gas or water for the oil rim models, while Fig. 5 shows the graphical representation of oil recovery with respect to base case (natural recovery). Water up-dip injection is depicted as the best scheme that gave a higher incremental oil recovery as compared to gas injection. Other important reservoir and operational factors such as values of reservoir dip, well completion and height of oil rim described by the Pareto chart also play an important role in increasing oil recoveries for both up-dip gas and up-dip water injection. Figure 6 shows the oil recovery plots from up-dip injection. Models 3, 6 and 10 incremental oil recoveries under water up-dip injection are worthy of note as its optimized parameters also cushioned recovery. The plots also showed that oil recovery under water up-dip injection is greater than for gas down-dip.

Phase 1: Down-dip injection (Case 2)

With the production wells of all the models at different respective locations way from the gas–oil contact, down-dip water injection gave a higher incremental oil recovery,

Table 7 Up-dip injection recoveries

Run no.	Base oil RF	Gas up-dip injection RF %	Water up-dip injection RF %	Incremental RF wrt gas up-dip injection %	Incremental RF wrt water up-dip injection %
Model 3	21.98	22.191	23.375	0.211	1.395
Model 4	1.076	3.99	5.044	2.914	3.968
Model 5	11.43	11.775	14.79	0.345	3.357
Model 6	6.675	7.23	10.707	0.56	4.032
Model 7	15.905	15.907	15.918	0.002	0.013
Model 9	17.36	17.653	17.659	0.293	0.3
Model 10	28.271	28.29	32.645	0.019	4.374
Model 14	8.622	11	11.075	2.378	2.453

Fig. 5 Oil recovery results from up-dip injection schemes with respect to base case

most especially for models 10 and 14 with smaller height of oil column. Water up-dip is advised for models where water down-dip resulted in lower oil recovery. Also, the nature of the reservoir drives also aided the water down-dip injection recovery, especially for reservoir 10 with a large gas cap and smaller aquifer. Table 8 shows the results of down-dip injections for both water and gas and the resulting incremental oil recovery, while Figs. 7 and 8 show the plot of oil recovery with respect to base case of no injection oil recovery plots from injection schemes, respectively. The plots from Fig. 9 show that down-dip water injection resulted in a higher oil recovery than down-dip gas injection.

Phase 2: Cases 3 and 4

This injection scheme will certainly yield higher oil recovery than a single point injection of fluids. The idea is that gas down-dip injection will produce a higher recovery than up-dip injection since the gas mobility in the lower region or down-dip region will be reduced due to the presence of

water and will also have to travel up-dip thus displacing more oil. Oil rim reservoirs with small gas caps and large aquifer had higher oil recovery under gas up-dip and gas down-dip injections, while oil rims with large gas caps and small aquifer recovered more oil than gas up-dip and gas down-dip injection. Water up-dip injection in large gas caps will tend to create a barrier for further gas coning and also serve as a good frontal displacement backed up with gas behind it. For example, reservoir 10 had incremental recovery of 7.069% compared to 6.514% for case 2 and 4.374% for case 1. It is normal to assume that comparing an injection scheme to another for a particular model classification may yield the same result. This may not be the case even as two models under the same classifications still possess varying properties which under Pareto analysis may be more significant to oil recovery. An example is reservoir model 6 and 14. Table 9 shows the oil recovery and incremental oil recovery results for the models under the injection schemes. The general trend observed is water injection at both up-dip and down-dip gave a higher oil recovery. An example is shown in Fig. 10 which shows a higher oil recovery from water up-dip and down-dip injection for reservoir model 3. From Fig. 9, water up-dip and water down-dip injection produced a higher recovery for reservoir model 6, while gas up-dip and gas down-dip injection produced a higher oil recovery for reservoir model 14 even though both are under the same classification.

Phase 2: Cases 5 and 6

Table 10 shows oil recovery results from simultaneous fluid injections at up-dip and down-dip location of the models. Table 10 and Fig. 11 show that irrespective of the classifications, oil rim models will behave differently to various injection schemes. These injection schemes for cases 3 and 4

Fig. 6 Oil recovery from case 1 **(a)** Reservoir Model 9 **(b)** Reservoir Model 5 **(c)** Reservoir Model 6 **(d)** Reservoir Model 7 **(e)** Reservoir Model 14 **(f)** Reservoir Model 10**Table 8** Down-dip injections

Run no.	Base oil RF	Water down-dip injection RF %	Gas down-dip injection RF %	Incremental RF wrt water down-dip injection %	Incremental RF wrt gas down-dip injection %
Model 3	21.98	23.048	22.218	1.068	0.238
Model 4	1.076	5.04	3.99	3.964	2.914
Model 5	11.43	12.961	11.983	1.531	0.55
Model 6	6.675	11.948	7.27	5.273	0.6
Model 7	15.905	15.917	15.905	0.012	0
Model 9	17.36	17.63	17.63	0.27	0.27
Model 10	28.271	34.784	28.29	6.514	0.019
Model 14	8.622	11.67	11.43	3.048	2.808

Fig. 7 Oil recoveries from injection schemes

performed better in terms of oil recovery compared to cases 1 and 2. Figure 12 shows oil recovery for models 3 and 14.

For this case study, the incremental oil recoveries for majority of the models were almost the same, especially for models 4, 7, 6 and 9. Model 3 favorably produced more oil under water up-dip and gas down-dip injection due to the presence of the large gas cap that backed up the injected water up-dip and the presence of large gas cap that backed up the injected gas down-dip. Model 14 even though with a small gas cap produced more oil under gas up-dip and water down-dip injection due to its completion farther away from the aquifer, so as the source of reservoir drive is the aquifer, oil is pushed up toward the well and since a weak gas cap exists and gas injection rate at the up-dip is low, the resulting effect is an increase in oil recovery.

Phase 3: Case 7

A case 5 injection scheme was put in place to estimate the extent and impact of increasing injection rates on oil recovery. The injection schemes with the highest oil recoveries from phase 1 were selected, and an optimized injection rates were simulated to ascertain the extent of oil recovery. Water injection rate was increased from 5000 to 15,000 stb/day for reservoir cases 3, 4, 9, 10 and 14. Reservoir case 5 injection rate was from 5000 stb/day of injected water to 9000 stb/day, while reservoir cases 6 and 7 were 6000 stb/day and 10,000 stb/day, respectively. However, the gas injection rate was increased from 500 to 1500 Mscf/day for all cases. The results obviously showed an increase in recovery as compared to cases 1–4 with up-dip and down-dip water injection giving the highest recovery. The injection rates proffered are

threshold limits for maximum oil productivity for different types of oil rims.

The oil recovery results from phase 3 injection patterns are higher than phases 1 and 2 injection schemes (Table 11). The injection rates used for the models are the optimum for each model. The simulation study has shown that increasing injection rates can increase oil recovery in thin oil rim reservoirs. Figures 13 and 14 show oil recovery charts and profiles with respect to base case for all injection patterns initiated. Models 8 had an incremental oil recovery of 8% under water up-dip and water down-dip injection over when the injection rates were not increased. Increasing injection rates during simultaneous down-dip and up-dip water injection produced the highest oil recovery from most of the models.

Conclusions and recommendation

The study has been able to show how a design of experiment can be used to create oil rim models and their further classification to create a path to perform and view the effectiveness of various production strategies. It has also shown that a concurrent oil and gas production presents a higher oil recovery compared to other schemes and an estimate response surface equation to represent oil and gas recovery under this scheme. Also, the estimation of oil recovery was done through proper strategic placement of water and gas injector wells. All cases that involved up-dip water injection schemes gave higher incremental oil recovery compared to other injection schemes. Oil displaced above the current well completions due to strong water drive is pushed downward by up-dip water injection. Up-dip water injection can avert the smearing of residual oil reserves into the overlying gas caps preventing loss of oil due to the upward movement of oil aided by a strong aquifer. In addition, injection rates should be optimized to prevent gravity segregation or viscous fingering. This is evident in the study as much oil was recovered when injection rates were increased for some of the oil rim models. For proper simulation study, it is suggested that other primary depletion strategies be initiated with secondary injection schemes and an enhanced oil recovery depletion strategy should be carried out to further increase oil recovery. For oil rims with very large gas caps, gas production is a major issue, and injecting of foams can help create a barrier restricting excess movement of gas (Olabode et al. 2018b).

(a) Reservoir Model 3

(b) Reservoir Model 5

(c) Reservoir Model 6

(d) Reservoir Model 7

(e) Reservoir Model 14

(f) Reservoir Model 10

Fig. 8 Oil recovery plots from down-dip injections

Fig. 9 Incremental oil recoveries

Fig. 10 Plot of oil recovery for reservoir model 3

Table 9 Gas up-dip/down-dip and water up-dip/down-dip injection recovery

Run no.	Base oil RF	Gas up-dip and gas down-dip RF %	Up-dip and down-dip water injection % RF	Incrmt. RF gas up-dip and gas down-dip %	Incrmt. RF water up-dip and water down-dip %
Model 3	21.98	22.431	23.945	0.45	1.965
Model 4	1.076	4.081	6.005	3.005	4.929
Model 5	11.433	12.304	14.161	0.871	2.728
Model 6	6.675	7.679	12.315	1.004	5.64
Model 7	15.905	15.907	15.94	0.002	0.035
Model 9	17.36	17.653	17.659	0.293	0.3
Model 10	28.271	28.301	35.34	0.03	7.069
Model 14	8.622	13.495	11.812	4.873	3.19

Table 10 Gas up-dip/down-dip and water up-dip/down-dip injection recovery

Run no.	Base oil RF	Gas down-dip and water up-dip RF %	Gas up-dip and water down-dip RF %	Incrmt. RF gas down-dip and water up-dip %	Incrmt. RF gas up-dip and water down-dip %
Model 3	21.98	23.584	23.127	1.604	1.147
Model 4	1.076	5.146	5.154	4.07	4.078
Model 5	11.433	15.428	13.075	3.995	1.642
Model 6	6.675	11.097	11.858	4.422	5.183
Model 7	15.905	15.919	15.921	0.014	0.016
Model 9	17.36	17.695	17.653	0.335	0.293
Model 10	28.271	33.9	35.982	5.629	7.711
Model 14	8.622	11.394	12.579	2.772	3.957

Fig. 11 Oil recoveries from injection schemes with respect to base case

Fig. 13 Injection recoveries and incremental recoveries with respect to base case

Reservoir model 3

Reservoir model 14

Fig. 12 Oil recovery from reservoir models 3 and 14

Table 11 Gas up-dip and water down-dip injection and gas down-dip and water up-dip (improved injection rate) recovery

Run no.	Base oil RF	RF %		Water up-dip and water down-dip injection % RF	Incrmt. RF gas down-dip and water up-dip %	Incrmt. RF gas up-dip and water down-dip %	Incrmt. RF water down-dip and water up-dip %
		Gas down-dip and water up-dip injection	Gas up-dip and water down-dip injection				
Model 3	21.98	25.86	26.53	25.86	3.88	4.55	3.88
model 4	1.076	6.65	7.347	8.27	5.574	6.271	7.194
model 5	11.43	19.8	12.622	15.779	8.37	1.192	4.349
Model 6	6.675	11.61	11.01	12.302	4.935	4.335	5.627
Model 7	15.91	15.97	15.964	17.562	0.065	0.059	1.657
Model 9	17.36	17.697	17.65	17.697	0.337	0.29	0.337
Model 10	28.27	39.065	39.835	43.701	10.794	11.564	15.43
Model 14	8.622	11.636	13.954	11.66	3.014	5.332	3.038

Fig. 14 Oil recovery from increasing injection rates

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Appendix

See Fig. 15.

Fig. 15 Plot of the PVT and solution properties

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