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Effect of foam and WAG (water alternating gas) injection on performance of thin oil rim reservoirs

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ABSTRACT

A design of experiment was used to create oil rim models from a wider range of reservoir, operational and reservoir architecture parameters. A response surface model was generated based on a concurrent oil and gas production and a Pareto analysis was conducted to ascertain the significance of the parameters. The models were classified based on the Pareto analysis and due to the low oil recoveries arising from the complexity of oil rims, a series of secondary injection schemes were instigated. The results from the models indicated an optimum 2 cycle WAG up dip injection and WAG down dip injection for thin oil rims. Also the results estimated an incremental oil recovery of 9.2% and 30.1% with respect to base case (no injection) for WAG up dip injection and 10.66% and 6.11% for WAG down dip injection while an incremental recovery of 14.2% and 52.74% for up dip foam injection and 18.19% and 29.73% incremental oil recovery for foam down dip injection for oil rim model '3' with large gas cap and large aquifer and model '7' with small gas cap small aquifer respectively. A case study reservoir from the Niger delta region of Nigeria showed an 8.57% and 8.56% incremental oil recovery for foam up dip and foam down dip injection and incremental oil recovery of 8.35% and 7.94% for WAG up dip and WAG down dip injection. This paper will provide useful information as to the extent of oil recovery in different oil rim models under different foam and WAG injection.

1. Introduction

This paper investigates the last series of depletion mechanism (enhanced oil recovery) for thin oil rim models and also a subject reservoir. It is important to note that a successful field study will attest to the validity models used in the study. Performance of thin oil as regards oil recovery is based on the reservoir parameters, production or operating strategies and recovery schemes initiated.

Ibunkun (2011) has highlighted factors that affect productivity of oil rim reservoirs. These factors can be grouped as reservoir, geological, dynamic and production factors. These parameters were also highlighted by (Vo et al., 2001) while investigating parameters affecting thin oil column. Uwaga and Lawal (2006) studied the viability of intermittent production of oil and gas and concluded that the strategy resulted in a rapid decline in oil production rate especially in oil rims with large gas caps. Wanye (2005) developed a matrix for evaluating development concepts for thin oil rims based on the size of the gas cap and the oil rim thickness. Masoudi (2013) described the pros and cons for developing oil rims as 4 major strategies which are: concurrent, sequential, swing and gas cap blow down.

Sensitivity analysis have majorly been carried out by changing parameters and evaluating their effects on estimated oil recovery. The results so far have not proved worthy of judging reserve estimates of oil rims as some reservoir parameters are static while others are dynamic.

Some authors described oil recovery in thin oil rims by initiating sensitivity analysis on oil rim parameters such as combining the effect of gas cap and aquifer length on optimal well location for oil rims as described by Iyare and Marcelle-De silva (2012) and this alone is not enough to predict the ultimate oil recovery in oil rims as there are a lot of factors affect the recoveries of thin oil rims depending on the nature of reservoir fluid properties and completions. Osoro et al. (2005) in their estimation of oil recovery only considered height of oil column as a major parameter. There was no dependency between recovery and parameters such as fluid properties, initial volumes of gas cap and reservoir geometry.

The best option in determining production strategy for thin oil rims is to subject various oil rim models to a range of strategies and evaluating the outcomes. A design of experiment will help in creating such

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Table 1
Oil rim uncertainties.

Parameter Range For The 15 uncertainties simulated					
	Parameters	Units	LOW	MID	HIGH
			−1	0	1
1	Dip Angle	degrees	1°	4	6
2	Gas Wetness (OGR)	stb/Mscf	0.006	0.03	0.04
3	Oil Column Height (Ho)	feet	20	40	70
4	M-factor (gas cap size) (m-factor)		0.7	3	6
5	Aquifer height to hydrocarbon thickness ratio (Aqfac)		0.7	3	6
6	Horizontal permeability (Kx, Ky)	mD	35	350	3500
7	Kv/Kh		0.001	0.01	0.1
8	Wellbore Diameter	feet	0.35	0.45	0.55
9	Oil Density	lb/cu. ft.	37	42	47
10	HGOC (Perforation with respect to the GOC)	feet	0.25	0.45	0.6
11	HWL (Horizontal well length)	feet	1200	1500	1800
12	Oil Rate (Qo)	stb/day	1200	2200	3500
13	Krw (Rel. perm. to water)		0.2	0.35	0.6
14	GOR control (*Rsi)		2.5	5	7.5
15	BHP (Bottomhole Pressure)	psia	1500	1800	2200

models from a wider range of uncertainties especially those neglected by authors which are reviewed later.

Design of experiments have been deployed to quantitatively asses various reservoir uncertainties by running sensitivities on all identified parameters with a limited number of simulation runs. Olamigoke and Peacock (2012), Kabir et al. (2004), Cosmo and Fatoke (2004) and Wanye (2005) applied the principle of experimental designs to assess the impact of oil and gas recovery for a specific range of uncertainties. The short fall of their study was disregarding dynamic and operational uncertainties such as well configuration, bottom hole pressure, horizontal well length and stand off point from gas oil and water oil contacts, reservoir geometry, formation volume factor, gas oil ratio constraint and relative permeability's just to mention a few. And most were majorly based on the assumptions that oil rims are majorly gas cap driven, thus a restriction to strong water drive, limited data source, disregarding other peculiar uncertainties such as mentioned above, not incorporating abandonment conditions such as gas oil ration, water cuts and pressures and no validation with production data have been some of the major setbacks of the reviewed literatures. Thus the resulting response surface model in terms of oil recovery is always void of important parameters that affect oil recovery.

Inadequacies of secondary injection schemes especially gas injection has necessitated further improvement by initiating water alternating gas injection schemes in oil rims. Mousa et al. (2011) in their studies analyzed the effects of improved WAG and simultaneous WAG injection in oil rims. Their injection schemes were at different locations with respect to the reservoir dip but they didn't consider WAG injection at a single location and also based their work on a single WAG cycle and a gas cap driven reservoir.

In their analysis of WAG injection in carbonate reservoirs using either Nitrogen or carbon dioxide as the gas continuous phase, Ghafoori et al. (2012) concluded that carbon dioxide is a better injection option for oil recovery optimization.

WAG injection is an enhanced oil recovery mechanism intentionally aimed to enhance the sweep efficiencies during gas injection. WAG injection helps to combine both improved displacement efficiency by gas flooding with an enhanced macroscopic sweep by water injection, to improve frontal stability or to contact unswept zones, is advantageous where gravity –stable gas injection is not feasible because of limited gas resources or reservoirs characterized by low dip angle or strong heterogeneity and also improves the microscopic displacement efficiency since residual oil saturations are always lower for WAG injection than for water flooding and obviously lower than for gas (Christensen et al., 2001).

Thang et al. (2010) initiated a series of injection schemes on a reservoir in the Samarang field offshore Malaysia and concluded that up dip gas injection and simultaneous up dip water injection and down dip gas injection gave highest oil recoveries (at 2 different locations in the reservoir). The increases represented an approximate 7% of OIIP. The injection schemes elaborately showed that additional oil can be recovered but are not they applicable to a wider range of oil rim types. It is reasonable to assume that different oil rims will show a different oil recovery to different injection schemes.

The major challenges with many gas injection projects are the incompetent gas utilization, poor sweep efficiencies and very low incremental oil recoveries that arises due to viscous instability (fingering or channeling) and gravity segregation. These challenges are caused by rock heterogeneity, low density and viscosity of injected gas.

Table 2
Main Plackett – Burman design of experiment (Olabode et al., 2018).

PLACKETT-BURMAN DESIGN OF EXPERIMENT (DOE) FOR 15 FACTORS

The design is for 16 runs (the rows of dPB) manipulating 15 two-level factors (the last seven columns of dPB)

The number of runs is a fraction 16/((2ˆ15)) = 0.00048828125 of the runs required by a full factorial design.

Run No.	Dip Angle	OGR	Ho	m-Factor	Aqfac	Kx, Ky	Kv/Kh	Bore Diam.	OIL DENSITY	HGOC	HWL	Qo	Krw	GOR (*Rsi)	BHP (psia)
Model 1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Model 2	−1	1	−1	1	−1	1	−1	1	−1	1	−1	1	−1	1	−1
Model 3	1	−1	−1	1	1	−1	−1	1	1	−1	−1	1	1	−1	−1
Model 4	−1	−1	1	1	−1	−1	1	1	−1	−1	1	1	−1	−1	1
Model 5	1	1	1	−1	−1	−1	−1	1	1	1	1	−1	−1	−1	−1
Model 6	−1	1	−1	−1	1	−1	1	1	−1	1	−1	−1	1	−1	1
Model 7	1	−1	−1	−1	−1	1	1	1	1	−1	−1	−1	−1	1	1
Model 8	−1	−1	1	−1	1	1	−1	1	−1	−1	1	−1	1	1	−1
Model 9	1	1	1	1	1	1	1	−1	−1	−1	−1	−1	−1	−1	−1
Model 10	−1	1	−1	1	−1	1	−1	−1	1	−1	1	−1	1	−1	1
Model 11	1	−1	−1	1	1	−1	−1	−1	−1	1	1	−1	−1	1	1
Model 12	−1	−1	1	1	−1	−1	1	−1	1	1	−1	−1	1	1	−1
Model 13	1	1	1	−1	−1	−1	−1	−1	−1	−1	−1	1	1	1	1
Model 14	−1	1	−1	−1	1	−1	1	−1	1	−1	1	1	−1	1	−1
Model 15	1	−1	−1	−1	−1	1	1	−1	−1	1	1	1	1	−1	−1
Model 16	−1	−1	1	−1	1	1	−1	−1	1	1	−1	1	−1	−1	1
Model 17	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1	−1
Model 18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 3
Placket – Burman design of experiment with reservoir uncertainties (Olabode et al., 2018).

PLACKETT-BURMAN DESIGN OF EXPERIMENT (DOE) FOR 15 FACTORS

The design is for 16 runs (the rows of dPB) manipulating 15 two-level factors (the last seven columns of dPB)

The number of runs is a fraction 16/((2ˆ15)) = 0.00048828125 of the runs required by a full factorial design.

Run No.	Dip	OGR	Ho (ft.)	m-Factor	Aqfac	Kx, Ky	Kv/Kh	Bore Diam. (ft)	oil density	HGOC (ft.)	HWL (ft.)	Qo Stb/day	Krw	GOR (*Rsi)	BHP (psia)
Model 1	6	0.04	70	6	6	3500	0.1	0.55	47	0.6	1800	3500	0.6	7.5	2200
Model 2	1	0.04	20	6	0.7	3500	0.001	0.55	37	0.6	1200	3500	0.2	7.5	1500
Model 3	6	0.006	20	6	6	35	0.001	0.55	47	0.25	1200	3500	0.6	2.5	1500
Model 4	1	0.006	70	6	0.7	35	0.1	0.55	37	0.25	1800	3500	0.2	2.5	2200
Model 5	6	0.04	70	0.7	0.7	35	0.001	0.55	47	0.6	1800	1200	0.2	2.5	1500
Model 6	1	0.04	20	0.7	6	35	0.1	0.55	37	0.6	1200	1200	0.6	2.5	2200
Model 7	6	0.006	20	0.7	0.7	3500	0.1	0.55	47	0.25	1200	1200	0.2	7.5	2200
Model 8	1	0.006	70	0.7	6	3500	0.001	0.55	37	0.25	1800	1200	0.6	7.5	1500
Model 9	6	0.04	70	6	6	3500	0.1	0.35	37	0.25	1200	1200	0.2	2.5	1500
Model 10	1	0.04	20	6	0.7	3500	0.001	0.35	47	0.25	1800	1200	0.6	2.5	2200
Model 11	6	0.006	20	6	6	35	0.001	0.35	37	0.6	1800	1200	0.2	7.5	2200
Model 12	1	0.006	70	6	0.7	35	0.1	0.35	47	0.6	1200	1200	0.6	7.5	1500
Model 13	6	0.04	70	0.7	0.7	35	0.001	0.35	37	0.25	1200	3500	0.6	7.5	2200
Model 14	1	0.04	20	0.7	6	35	0.1	0.35	47	0.25	1800	3500	0.2	7.5	1500
Model 15	6	0.006	20	0.7	0.7	3500	0.1	0.35	37	0.6	1800	3500	0.6	2.5	1500
Model 16	1	0.006	70	0.7	6	3500	0.001	0.35	47	0.6	1200	3500	0.2	2.5	2200
Model 17	1	0.006	20	0.7	0.7	35	0.001	0.35	37	0.25	1200	1200	0.2	2.5	1500
Model 18	4	0.03	40	3	3	350	0.01	0.45	42	0.45	1500	2200	0.35	5	1800

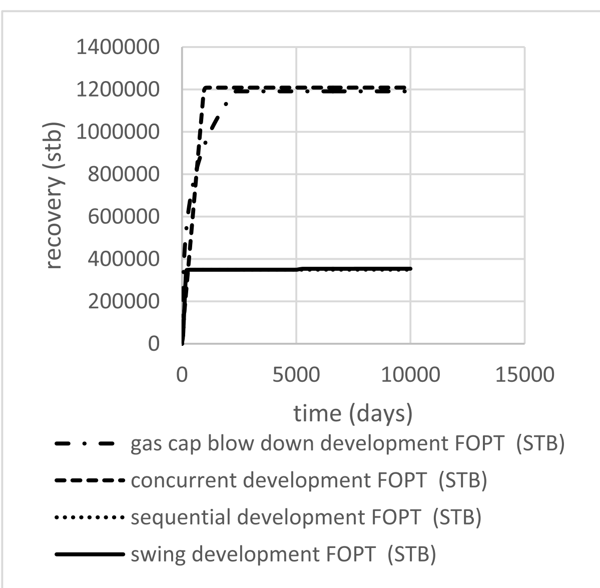


Fig. 1. Oil production for model 8.

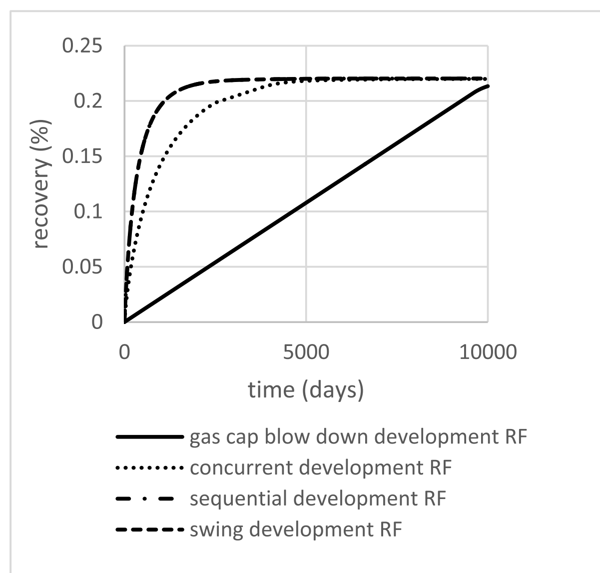


Fig. 2. Oil recovery factor for model 3.

To mitigate these drawbacks during gas injection processes, foams can be injected into the reservoir by co-injection of surfactant solution and gas or by surfactant alternating gas (SAG). Foam injection is normally initiated to increase gas density, thus reducing its mobility and hence reducing viscous fingering. According to (Liu et al., 2011), foams can also be injected into the formation by injecting surfactant solution into the upper region and gas is injected into the lower region. It is believed that foam injection will prove effective during gas injection in thin oil rims with large and small gas caps. Foam injection has not been recorded extensively in literatures but laboratory analysis has shown its effectiveness in improving oil recovery (Saleem et al., 2012).

2. Methodology

Using design of experiment (DOE), different developmental models or concept were built based on identified factors from important characteristics and reservoir uncertainties of thin oil rim reservoirs as seen in literatures. A linear screening of the reservoir uncertainties was conducted using Plackett-Burman design of experiments to determine the significant uncertainties. In this study, 15 identified uncertainties (reservoir, geological and dynamic) were selected from literatures. In order to analyze the 15 identified uncertainties, a 2-level 15 variable Plackett-Burman design was used to increase the strength of the linear screening, the folded Plackett-Burman with a center-point run (model 18) consisting of all mid-case was added. An extra run (Model 17) to define the minimum outcome was also introduced. Table 1 describes 15 parameter ranges for thin oil rims, there are 5 dynamic parameters, 1 geological parameters and 9 reservoir parameters. Table 2 describes the 2 level Plackett-Burman design of experiment spatial distribution of variables and Table 3 describes the Burman design of experiment with reservoir uncertainties.

Table 4
Summary of oil recoveries from production strategies.

Reservoir type	Production strategy recoveries							
	Concurrent		Swing		Sequential		Gas cap blow down	
	Foe (%)	Fopt (stb)	Foe (%)	Fopt (stb)	Foe (%)	Fopt (stb)	Foe (%)	Fopt (stb)
Model 3	21.99	1,222,785.1	22.0	1,225,171.9	22.02	1,224,983.3	21.3	1,186,643.5
Model 8	5.14	1,208,875.1	1.51	354,253	1.49	349,770	4.91	1,191,053.5
Model 13	6.66	1,136,244.9	4.59	783,493	4.59	783,317.88	5.91	1,009,297.3
Model 16	6.48	1,499,402.1	1.55	358,717.97	1.54	355,055	4.94	1,142,099.4

Table 5
Oil and Gas initial, produced and recovery factors for oil rim models under concurrent oil and gas production.

Cumulative oil production						Cumulative gas production				
Model no	CUMM. PROD. (stb)	OIIP (Mstb)	RF (%)	OCIP (Mstb)	NFA	GIIP (Mscf)	CUMM. PROD. (Mscf)	RF (%)	GCIP (Mscf)	NFA
model 1	3,780,909	26,905	14	23,124	1095	589,284	277,540	47.1	311,744	1055
Model 2	1,313,602	8471	16	7157	376	286,844	198,933	62.9	87,911	376
Model 3	1,222,449	5,561,6	22	4339	3995	315,410	203,742	64.6	111,668	3960
Model 4	299,295	28,071	1	27,773	1609	330,684	50,000	15.1	280,684	1410
Model 5	1859613	16,267	11	14408	6204	96,761	63,316	65.4	33,445	6000
Model 6	316218	4,690,	7	4374	6000	62,184	28,892	46.5	33,292	6000
Model 7	914,593	5,750,	16	4836	740	412,231	152,432	37.0	259,799	740
Model 8	1,208,603	23,521	5	22,312	1000	42,015	22,561	53.7	19,454	1128
Model 9	10750810	60,981	18	50230	8672	1,009,138	620,356	61.5	388,782	8660
Model 10	1,284,098	4542	28	3258	1069	122,448	49,020	40.0	73,428	1069
Model 11	387,335	4161	9	3773	7990	135,949	64,556	47.5	71,393	8000
Model 12	1,971,314	25,498	8	23,527	4000	612,799	445,696	62.5	167,103	4000
Model 13	1,154,199	17,063	7	15,909	5793	97,566	37,710	38.7	59,856	6000
Model 14	248,143	2878	9	2630	270	20,356	12,944	63.6	7412	542
Model 15	191,164	2728	7	2549	70.5	65,116	31,860	48.9	33,256	70.5
Model 16	1,499,402	33,279	7	21,631	470	68,235	27,672	40.6	40,563	470
Model 17	88,231	3495	3	3406	3000	20,049	12,999	64.8	7050	3000
Model 18	457,304	11,989	4	11,532	1000	132,143	50,000	37.8	82,143	10000

*where OIIP is oil initially in place, OCIP is oil currently in place, GIIP is gas initially in place, GCIP is gas currently in place and NFA means no further action.

Two horizontal production wells were initiated in the model with one an oil well and the other a gas well. The oil well production rates, horizontal well lengths and height of perforations to GOC varies in accordance to are as described in Table 1 while the gas production rates were fixed at 1000 Mscf/day.

Since a concurrent oil and gas production was initiated, a response surface model for ultimate recovery of oil and gas was derived as seen in the 2 equations below:

$$\text{Recovery Factor } (\eta_{oil}) = 11.4465 + 12.0662*(Dip\ Angle) + 17.3848*(OGR) - 42.522*(H_o) + 47.9824*(mFactor) - 3.3584*(Aqfac) + 34.9484*(K_x,K_y) - 26.64*\left(\frac{K_v}{K_h}\right) + 0.3896*(Wellbore\ Diameter) + 45.8114*(Oil\ Density) - 27.632*(HGOC) - 14.216*(HWL) - 21.052*(Oil\ Rate) + 11.2064*(K_{rw}) - 17.07*(GOR) - 6.0624*(BHP) \tag{1}$$

$$\text{Recovery Factor } (\eta_{gas}) = 49.71483 - 12.8896.1*(Dip\ angle) + 27.9174*(OGR) - 13.1532*(H_o) + 3.426585*(mFactor) + 27.20964*(Aqfac) - 6.14772*(K_x,K_y) - 15.619075*\left(\frac{K_v}{K_h}\right) - 5.44819*(Wellbore\ Diameter) - 23.0930*(Oil\ Density) + 26.60462*(HGOC) - 16.3405*(HWL) - 16.3765*(Oil\ Rate) + 36.9368*(K_{rw}) + 15.1330*(GOR) - 85.3602*(BHP) \tag{2}$$

Both equations has shown the contributive effects of all variables as they affect the oil and gas recovery under a concurrent production. It should be noted that the negative values associated with a variable suggests that its increase has an adverse on the optimized variable, recovery factor, in this case. The opposite is true for a positive value.

2.1. Production plan

To estimate a good primary oil recovery for oil rim reservoirs and improve the field net present value and overall economics from the possibilities of gas sales, 4 production strategies were initiated to develop the models. These production plans are Concurrent, Swing production, Gas cap blow down and Sequential production. In Concurrent production, oil production was done simultaneously with gas production using two different wells, but the oil wells were converted to gas wells to initiated full gas production from inception for gas cap blow down.

The simulation run period is divided into 2 and our second period was run on gas production (at 5000 days) for sequential production while swing production was alternated for oil production then gas production every 2500 days. Oil production rates were fixed at 1500 stb/day while the gas cap off takes rates were 5% of gas initially in place. Fig. 1 shows oil recovery for model 8 and Fig. 2 recovery factor for model 3 while Table 4 shows the oil recovery summary for the 4 models. The results shows that on recovery basis, concurrent oil and gas strategy gave the highest oil recovery even with the gas production, oil production wasn't jeopardized.

Using the Eclipse software, PVT and solution properties for a black oil reservoir was initiated for all the models and a concurrent production of oil and gas with from 2 different horizontal wells is attached to all the models. The oil well production rates, horizontal well lengths and height of perforations to GOC varies in accordance to are as described in Table 1 while the gas production rates were fixed at 1000 Mscf/day. Table 5 describes the gas and oil recovery factors for all the

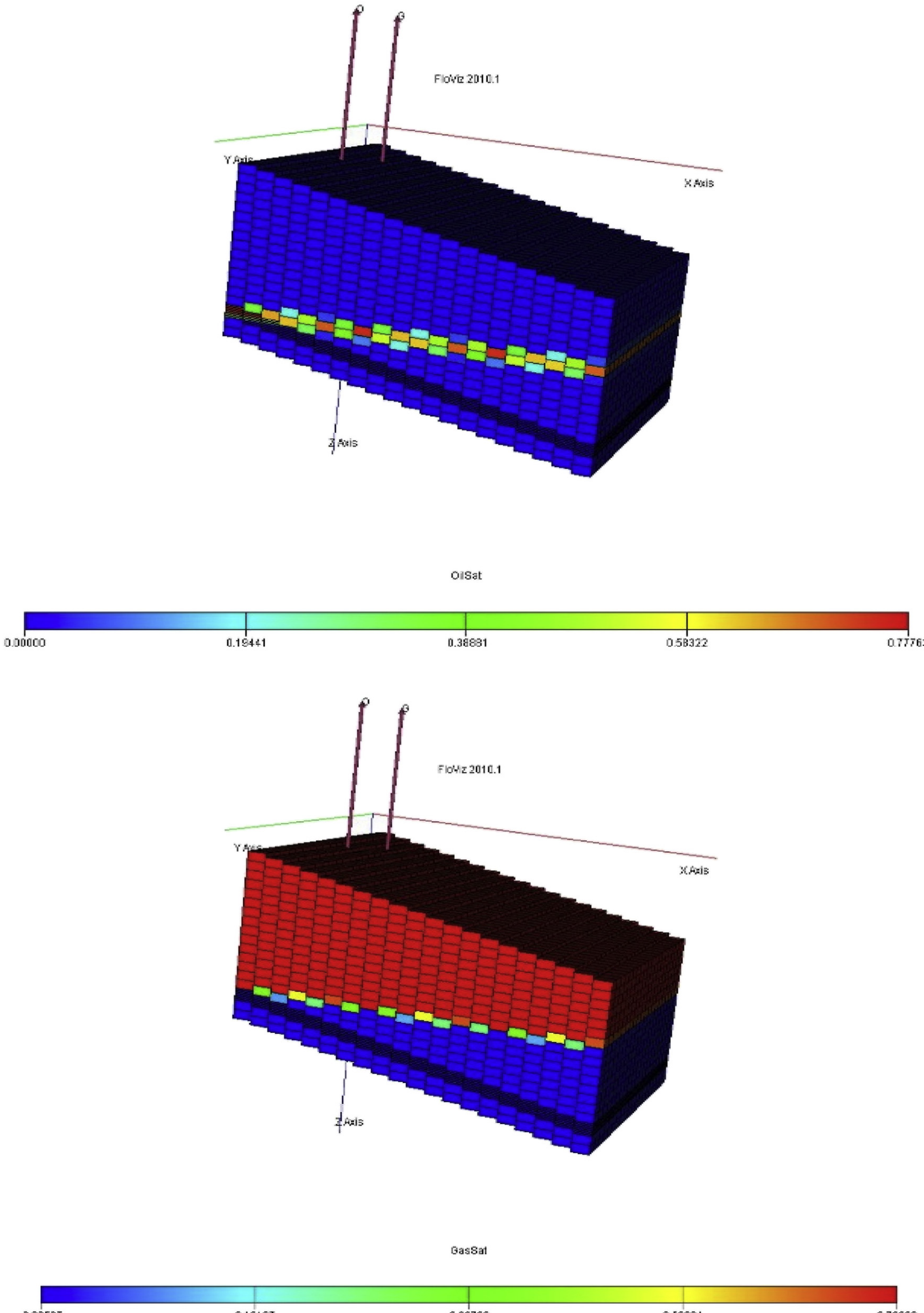


Fig. 3. : Fluid saturations for model 3.

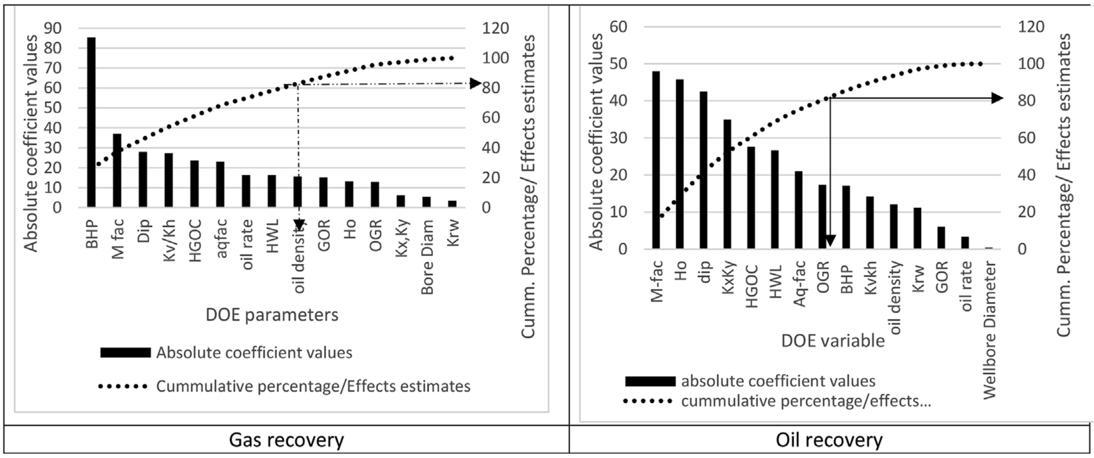


Fig. 4. Pareto chart results for oil and gas recoveries.

Table 6
Simulation injection models.

Reservoir type	Simulation models	Respective percentage oil recoveries
Large gas cap large aquifer	3, 9,	21.98, 17.36,
Large gas cap small aquifer	4, 10	1.076 28.271
Small gas cap large aquifer	6, 14	6.675, 8.622
Small gas cap small aquifer	5, 7,	11.433, 15.905

models and also including the initial and final reserve estimates.

Fig. 3 shows the reservoir fluids saturation and equations (1) and (2) below describes the ultimate recovery factors for gas and oil productions representing all the models.

$$\text{Recovery Factor }(\eta_{oil}) = 11.4465 + 12.0662*(Dip) + 17.3848*(OGR) - 42.522*(H_o) + 47.9824*(mFactor) - 3.3584*(Aqfac) + 34.9484*(K_xK_y) - 26.64*\left(\frac{K_v}{K_h}\right) + 0.3896*(Wellbore\ Diameter) + 45.8114*(Oil\ Density) - 27.632*(HGOC) - 14.216*(HWL) - 21.052*(Oil\ Rate) + 11.2064*(K_{rw}) - 17.07*(GOR) - 6.0624*(BHP) \quad (3)$$

$$\text{Recovery Factor }(\eta_{gas}) = 49.71483 - 12.8896.1*(Dip) + 27.9174*(OGR) - 13.1532*(H_o) + 3.426585*(mFactor) + 27.20964*(Aqfac) - 6.14772*(K_xK_y) - 15.619075*\left(\frac{K_v}{K_h}\right) - 5.44819*(Wellbore\ Diameter) - 23.0930*(Oil\ Density) + 26.60462*(HGOC) - 16.3405*(HWL) - 16.3765*(Oil\ Rate) + 36.9368*(K_{rw}) + 15.1330*(GOR) - 85.3602*(BHP) \quad (4)$$

Table 7
Foam property data.

Description	values	
FOAMADS	Flc (lb/stb)	Fsc (lb/stb)
	0	0
	1	1E-5
	10	5E-5
FOAMMOB	Conc (lb/stb)	Fm
	0	1
	0.001	0.4
	0.1	0.1
	1.2	0.05
FOAMMOBP	Poil (psia)	Mp
	2000	0
	4000	1E-6
FOAMMOBS	Gas phase flow velocity	Shear modifier
	0	0
	4	1E-6
FOAMDCYW	Lcl Sw	DHL (day)
	0	3000
	1	
FOAMDCYO	Slo	Dhl (day)
	0	3000
	1	2500
FOAMROCK	Adsorption index	Rock mass density lb/ft^3
	2	2560

Applying the Pareto 80/20 rule as shown in Fig. 4, factors or uncertainties such as bottom hole pressure, oil gas ration, gas cap size, aquifer size, horizontal height completion to gas oil contact, dip, oil rate and horizontal well length significantly affect gas ultimate recovery

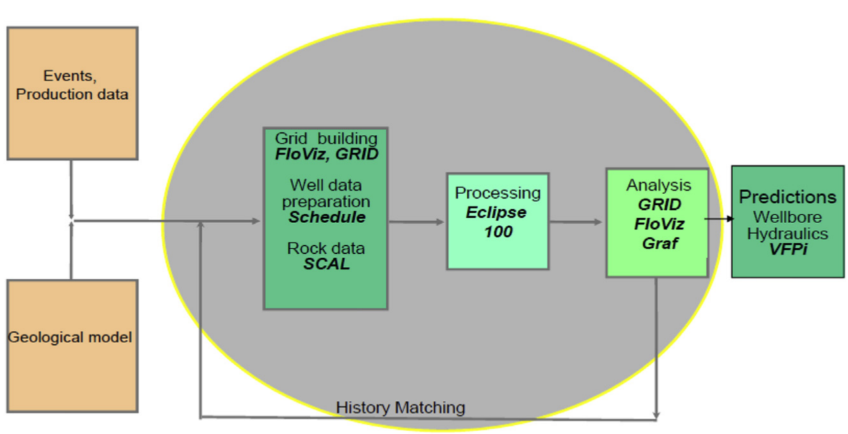


Fig. 5. : Reservoir E2 study workflow.

Table 8
WAG injection oil recovery.

		WAG CYCLE 1			WAG CYCLE 2			WAG CYCLE 3		
Run No.	Base oil RF	incrmt WAG updip injtn	incrmt WAG downdip injtn	incrmt WAG injtn @ GOC	incrmt WAG updip injtn	incrmt WAG downdip injtn	incrmt WAG injtn @ GOC	incrmt WAG up dip injtn	incrmt WAG down dip injtn	incrmt WAG injtn @ GOC
Model 3	21.98	4.986	0.738	0.503	**4.986**	**7.534**	**0.993**	4.986	7.53	5.16
Model 4	1.076	30.174	4.216	3.572	**30.174**	**19.802**	**4.017**	30.174	19.80	7.25
Model 5	11.43	1.315	0.665	−2.89	**11.467**	**1.383**	**−2.31**	11.467	6.61	−2.31
Model 6	6.675	6.838	3.761	2.325	**7.241**	**7.083**	**2.325**	7.241	7.08	2.323
Model 7	15.91	22.675	5.314	−0.137	**22.675**	**23.611**	**−0.137**	22.675	23.61	−0.14
Model 9	17.36	2.91	0.27	1.733	**2.91**	**0.27**	**3.09**	2.91	0.27	3.09
Model 10	28.27	14.479	18.959	5.237	**51.32**	**42.376**	**16.082**	51.32	42.38	16.08
Model 14	8.622	15.548	3.39	2.053	**17.148**	**4.649**	**2.256**	17.148	4.65	16.63

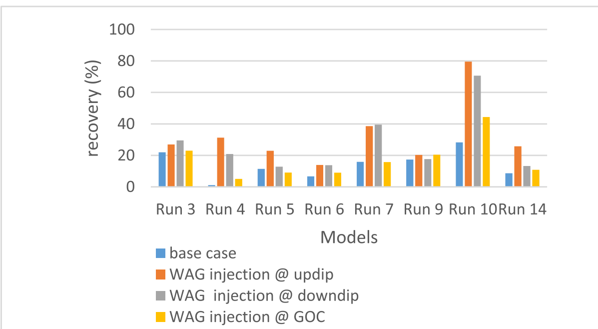


Fig. 6. Oil recovery from WAG injection (cycle-2).

under concurrent oil and gas production while gas cap size, dip, horizontal permeability, oil rim thickness, oil rate and oil gas ratios are the main factors affecting ultimate oil recovery under concurrent oil and gas production. The models were later classified (based on the Pareto analysis) with respect to the sizes of the reservoir drives (gas cap and aquifer) as seen in the Table 6. 8 models were eventually selected for enhanced oil recovery schemes based with respect to the reservoir geometry. The results tabulated were based on the incremental recoveries of foam and WAG injection with respect to the base case.

The E2 thin oil rim reservoir is one of the many found in the Niger delta region of Nigeria. It has 5 drainage points and reservoir sand porosity was 0.24 with an oil viscosity of 0.43cp. The oil thickness was 71 ft which is less than 100 ft thus indicating an oil rim. The initial reservoir pressure was at its bubble point pressure of 4394 psi indicating an existing gas cap drive and solution gas drive. Stock tank oil initially in place was 35.9 MMstb while produced oil stood at 10.73 MMstb. Free gas in place was 128.5 Bscf four times that of oil. Reservoir GOR is 1035 scf/stb which proves a significant amount of gas produced from the gas cap while reservoir oil permeability ranged from 400 to 1500 milli Darcy. Fig. 5 below shows study work flow for E2 sands. A WAG injection model was considered for 3 injection cycles. As mentioned earlier the injection cycles commenced on the onset of reduction in oil production rate. WAG cycles of 6 months interval (180 day) was initiated for all the simulation runs. Injection rates were initially varied to suggest the optimum rate of injection. 20,000 bbl/day and 7000 Mscf/day were injected for run 3, 50000 Mscf/day and 100000 stb/day for run 4, 8000 Mscf/day and 20000 stb/day of r for run 5. For run 6 up dip WAG injection, 25000 Mscf/day and 70000 stb/day was injected for cycle 1 and 4500 Mscf/day and 10000 stb/day of gas and water was injected for cycle 2. Injection rates at the GOC and down dip were both 3000 Mscf/day and 9000 stb/day. Injection rates for run 7 and 9 were 50000 Mscf/day and 300000 stb/day and 200000 Mscf/day and 300000 stb/day of respectively. Up dip injection rate for run 10 cycle 1 was 10000 Mscf/day and 100000 stb/day while cycle 2 and 3 were at 50000 Mscf/day and 200000 stb/day. Down dip injection rates for cycles, one and two were 50000 Mscf/day and 200000 stb/day and 25000 Mscf/day and 100000 stb/day respectively. Injection rates for run 14 at GOC and down dip was 10000 Mscf/day and 300000 stb/day. CO_2 gas injection rates were kept below the minimum miscibility pressures to attain an immiscible WAG injection.

In describing the foam injection parameters for the models and our case study reservoir the gas mobility reduction factor is modeled in terms of a set of functions which represent the individual reduction factors due to surfactant concentration (FOAMFSC keyword), oil saturation (FOAMFSO keyword), water saturation (FOAMFSW keyword) and capillary number (FOAMFCN keyword) which are all initialized using Eclipse. These are combined multiplicatively with a reference mobility reduction factor (FOAMFRM keyword) to determine the net mobility reduction factor. Table 7 is a description of the keywords and values used in foam simulation. CO_2 was used as the gas carrier phase for foam injection and also during WAG process. Foam injection was applied for reservoirs 3,7,10 ad 14. Up dip and down dip foam injections were simulated. The gas injection rate was varied at 50000, 100,000 and 150,000 Msc/day. Foam concentration was fixed at 1 lbs/stb. The water injection well was shut in since foam suffers enhanced decay in the presence of water.

3. Results

The results in Table 8 shows Wag injection strategies implemented with respect to locations for all the models. it has indicated that WAG injection (2 cycle) gave the optimum recovery thus a further third cycle will be unnecessary. Fig. 6 shows the incremental recovery from WAG (2 cycle) injection for the specified models, while Fig. 7 shows WAG recovery for the reservoir models.

Even though, the oil rims have been classified accordingly, oil recovery for a particular classification under an injection scheme may not be the same since each models have different properties. For example model 3 and 9 are grouped as large gas cap large aquifer models and one would expect that an injection scheme (WAG down dip) for both will produce a higher recovery. This is not so as they have other uncertainties that are significant as described by the Pareto analysis that contributes to oil recovery. And this can be said of the other classified models. The general trend from (Fig. 6) shows that WAG up dip injection is better viable option for optimum oil recovery.

As seen from the result there was a remarkable increase in oil recovery especially for down and up dip WAG injection schemes. Runs 4,7 and 10 had a remarkable 15%,18% and 24% respectively increase in oil recovery for down dip injection from cycle 1 while for up dip WAG injections, Runs 4 and 10 had 10% and 37% increase in oil recovery from cycle 1. It is evident from our results that WAG (2 cycle) did better than any other injection scheme carried out so far. A base case of gas injection rate of 150,000 Mscf/day during foam injection was used to compare recoveries with WAG injection. The case shows that Foam up and down dip injection gave a better result in terms of oil recovery compared with WAG up and down dip injections. The physics of transportation leading to increased oil recovery is almost the same as

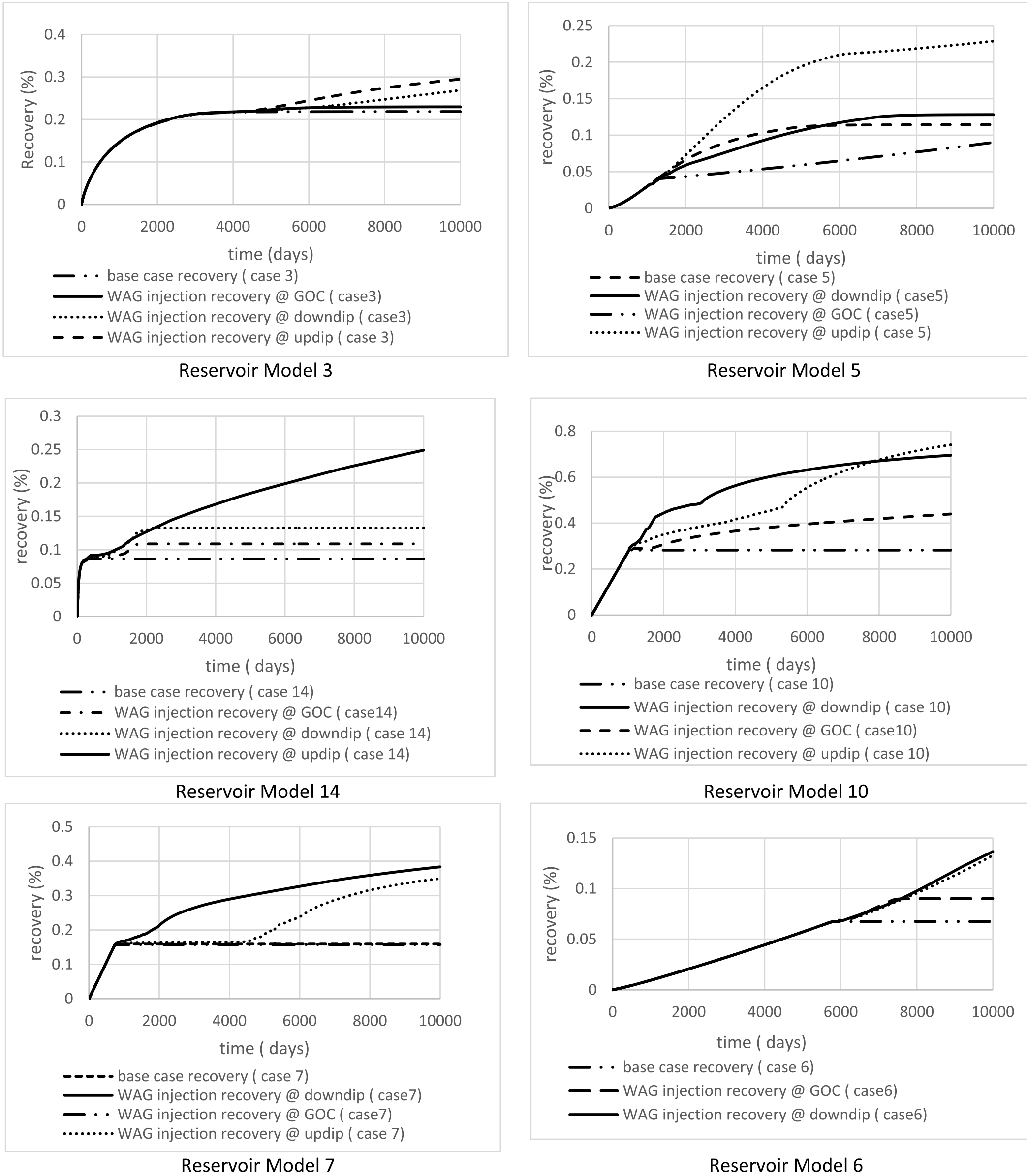
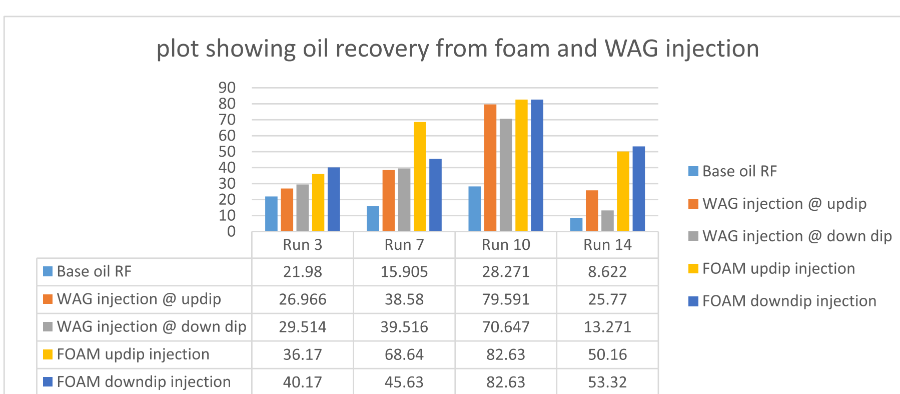


Fig. 7. Oil recovery from models under WAG injection (Cycle-2).



	Run 3	Run 7	Run 10	Run 14
Base oil RF	21.98	15.905	28.271	8.622
WAG injection @ updip	26.966	38.58	79.591	25.77
WAG injection @ down dip	29.514	39.516	70.647	13.271
FOAM updip injection	36.17	68.64	82.63	50.16
FOAM downdip injection	40.17	45.63	82.63	53.32

Fig. 8. Plot showing oil recoveries from foam and WAG injection.

WAG injection. The foam been carried by gas is lighter and more mobile thus making it easier to move from down dip to up dip thereby diverting more gas to un-swept zones instead of towards production well.

For reservoir 3,10 and 14 the additional recovery for foam down dip injection was 10.656%,11.983% and 40.049% and this is with respect to WAG down dip as base case and an additional oil recovery of

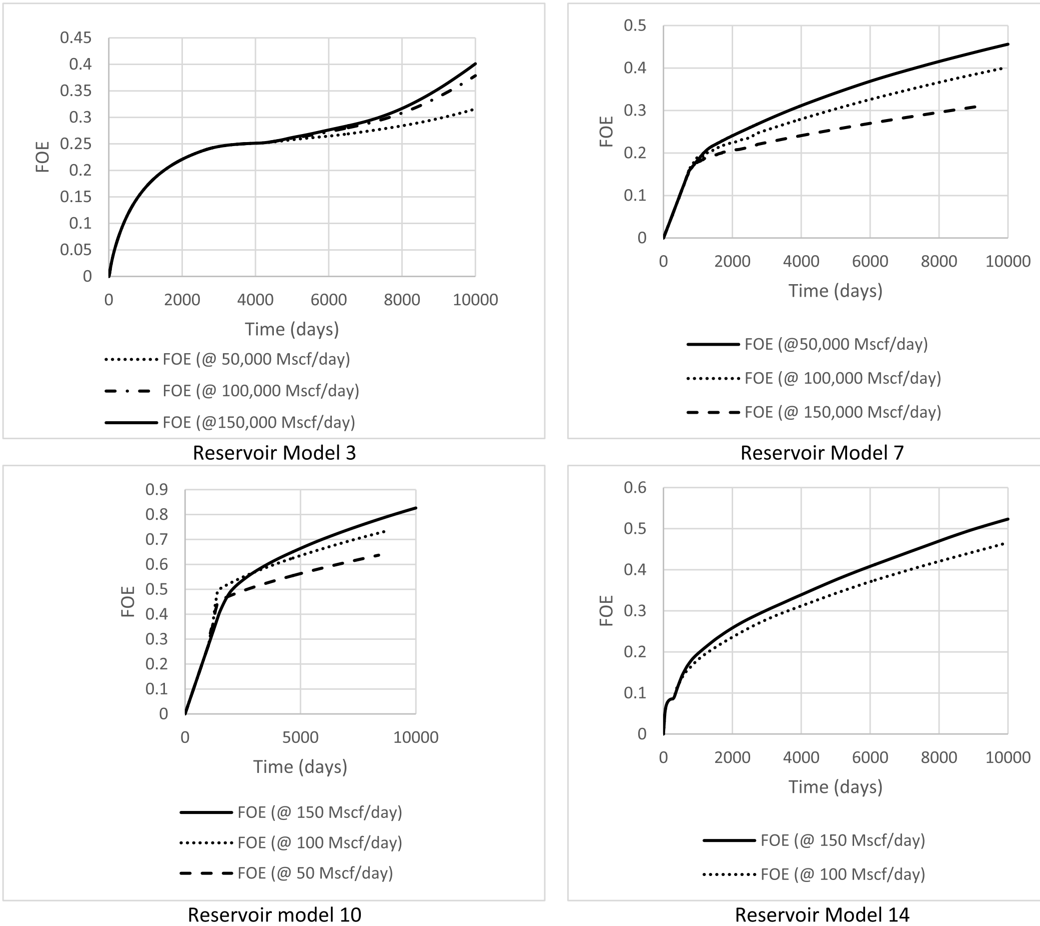


Fig. 9. Oil recoveries from foam injection schemes.

Table 9
Oil recoveries from foam injection with respect to varying injection location and rates.

reservoir	Up dip oil recovery		Down dip oil recovery	
3	@ 50,000 Mscf/day	32.94%	@ 50,000 Mscf/day	31.94%
	@ 100,000 Mscf/day	33.66%	@ 100,000 Mscf/day	37.91%
	@ 150,000 Mscf/day	36.17%	@ 150,000 Mscf/day	40.17%
7	@ 50,000 Mscf/day	47.07%	@ 50,000 Mscf/day	31.27%
	@ 100,000 Mscf/day	60.29%	@ 100,000 Mscf/day	39.91%
	@ 150,000 Mscf/day	68.64%	@ 150,000 Mscf/day	45.63%
10	@ 50,000 Mscf/day	63.70%	@ 50,000 Mscf/day	63.70%
	@ 90,000 Mscf/day	73.36%	@ 90,000 Mscf/day	73.36%
	@ 150,000 Mscf/day	82.63%	@ 150,000 Mscf/day	82.63%
14	@ 100,000 Mscf/day	41.23%	@ 100,000 Mscf/day	46.5%
	@ 150,000 Mscf/day	41.24%	@ 150,000 Mscf/day	52.32
	@ 200,000 Mscf/day	50.16%		

9.2%,30.1%,3.04% and 24.39% from foam up dip injection with our base case as WAG up dip injection. The Fig. 8 shows the comprehensive oil recovery results for foam and WAG injection while Fig. 9 describes the oil recovery from oil rim models at varying gas injection rates. Table 9 show oil recoveries from foam injection with respect to varying injection location and rates.

After history matching production data for our case study reservoir with the five initial wells (Fig. 10), 8 horizontal producer wells were attached and the reservoir produced under concurrent oil and gas production (Fig. 11). The prediction started a month after history matching and it elapsed for 16 years. The cross flow between the layers due to (drawdown) or production was accurately depicted to visualize reduction in oil saturations. The average horizontal well length is 2000 ft and all perforated in the x direction. A total of 1,410,436 barrels of oil was produced after history matching signifying a 5.9% increase in oil recovery. An injection rate of 5000 Mscf/day and 10,000 bbl./day of gas and water was injected respectively. A production rate of 2000 stb/day of oil was maintained for production wells and the well economic limits was maintained at 100 bbl./day, 10 Mscf/day was maintained for oil and gas. The data used for foam injection are similar to those used in our models with the exception of gas injection rate which was at 5000 Mscf/day. Table 10 shows oil recoveries from each wells for foam and WAG injections while Table 11 shows the summary of overall oil recovery. Fig. 12 describes total oil production from foam and WAG injection schemes on the case study reservoir.

The results obtained from the Niger delta oil rim model is similar to the synthetic models. WAG injection at the GOC was not considered for the Niger delta as its results (oil recovery) from the synthetic models were low. Oil recovery from Foam up dip and foam down dip injection was higher than WAG injection schemes for both models and foam up dip injection gave the highest oil recovery for all synthetic models considered (irrespective of the reservoir and operational properties) and the Niger delta case study.

4. Conclusions and Recommendations

The results obtained from the thin oil models and E2 reservoir shows that foam injection has a major advantage in improving oil recovery especially since when most oil rims are accompanied by gas caps 5 to 6 times bigger than them. The simulation studies also shows that foam injection fully utilizes the effectiveness of gas injection than in WAG injection as seen in the oil recoveries. Models who's horizontal well completions were closer to the WOC due to large gas caps did well

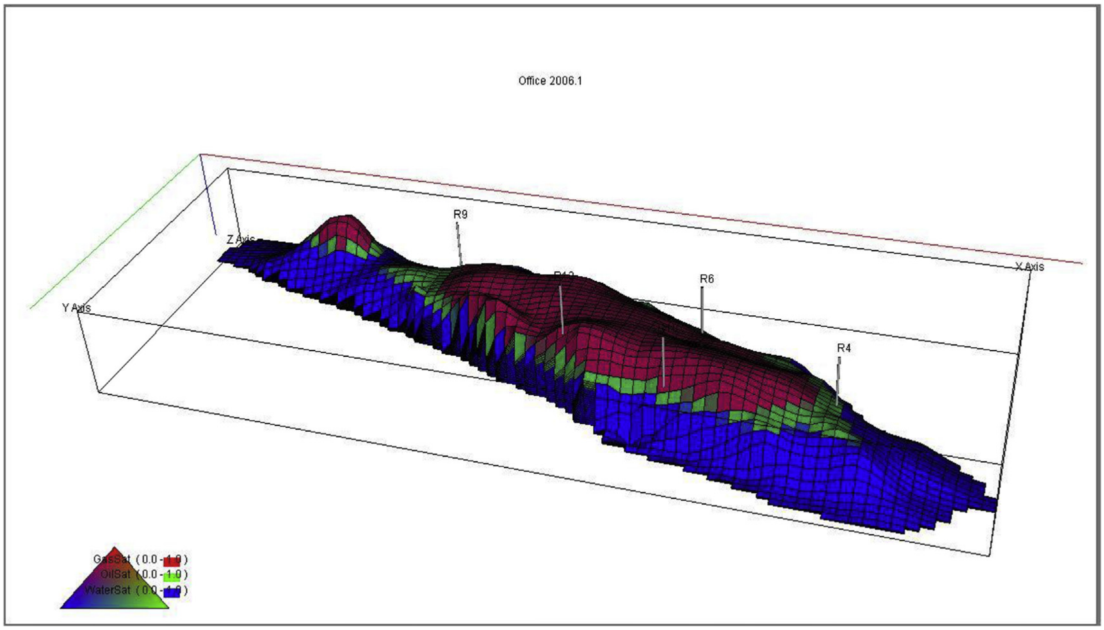


Fig. 10. Ternary diagram showing initial fluid distribution and well locations.

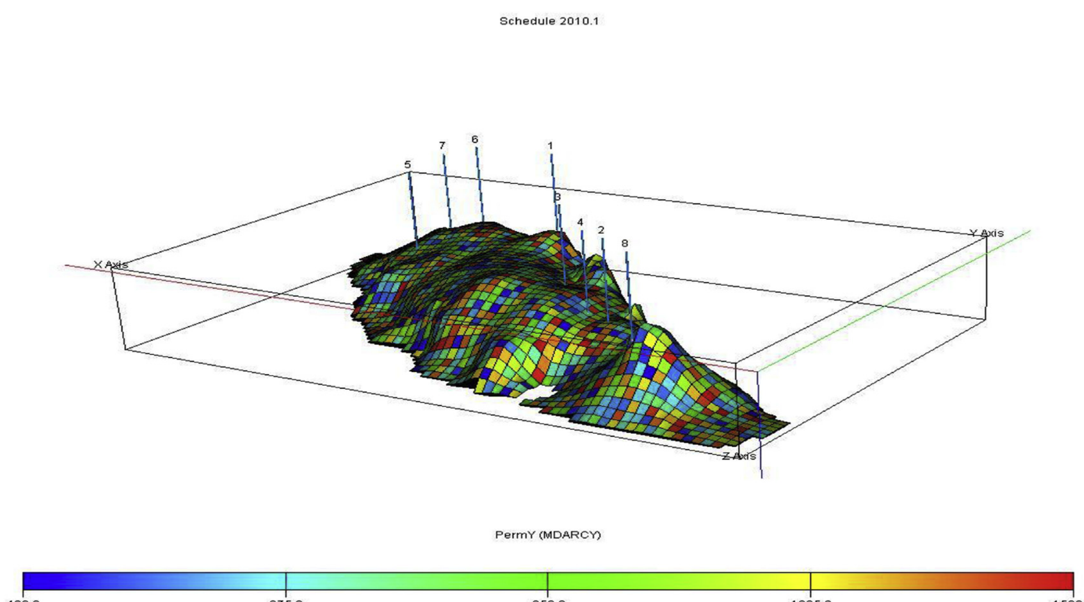


Fig. 11. Permeability distributions showing 8 prediction production wells.

Table 10
Well oil production (no injector).

Prediction scenario (stb)	WELLS							
	1	2	3	4	5	6	7	8
No injector	134,763.5	265,428.6	150,571	30,725.1	174,766.4	286,592.8	362,103.6	5485.43
Down dip WAG injection	151,064.9	403,325.5	281,574	137,013.7	327,516.75	409,491.38	409,444.53	37,649.46
Up dip WAG injection	163,854.9	472,333.8	288,357	215,326.3	332,180.34	409,601.91	408,249.09	12,775.208
Foam up dip injection	174,786.0	523,792.8	278,445	176,174.8	350,714.84	409,695.44	375,969.06	154,555.81
Foam down dip injection	167,061.1	479,075.8	279,899	186,808.6	339,151.75	409,638.34	394,814.94	128,769.84

Table 11
Summary of oil recovery from injection schemes.

Recovery type	Recovery (stb)	Recovery (%)
Natural (no injector)	1,410,436	5.9
WAG up dip injection	2,302,678.618	8.35
WAG down dip injection	1,747,589.23	7.94
Foam Up dip injection	2,444,133.34	8.57
Foam down dip injection	2,385,218	8.56

in terms of oil recovery under foam down dip injections and models with smaller gas caps and a closer completions to the GOC performed well under foam up dip injection. Even though reservoir properties were different for all the models but homogenous as a model, they showed the same traits in terms of oil recoveries during the implementation of enhanced oil recovery schemes. There is considerable cross flows of reservoir fluids during injection thus infill wells can be used to tap into oil that has been displaced although this could have been properly checked by a good production and injector well positioning plan. Also, infill wells can be used to target remaining oil that

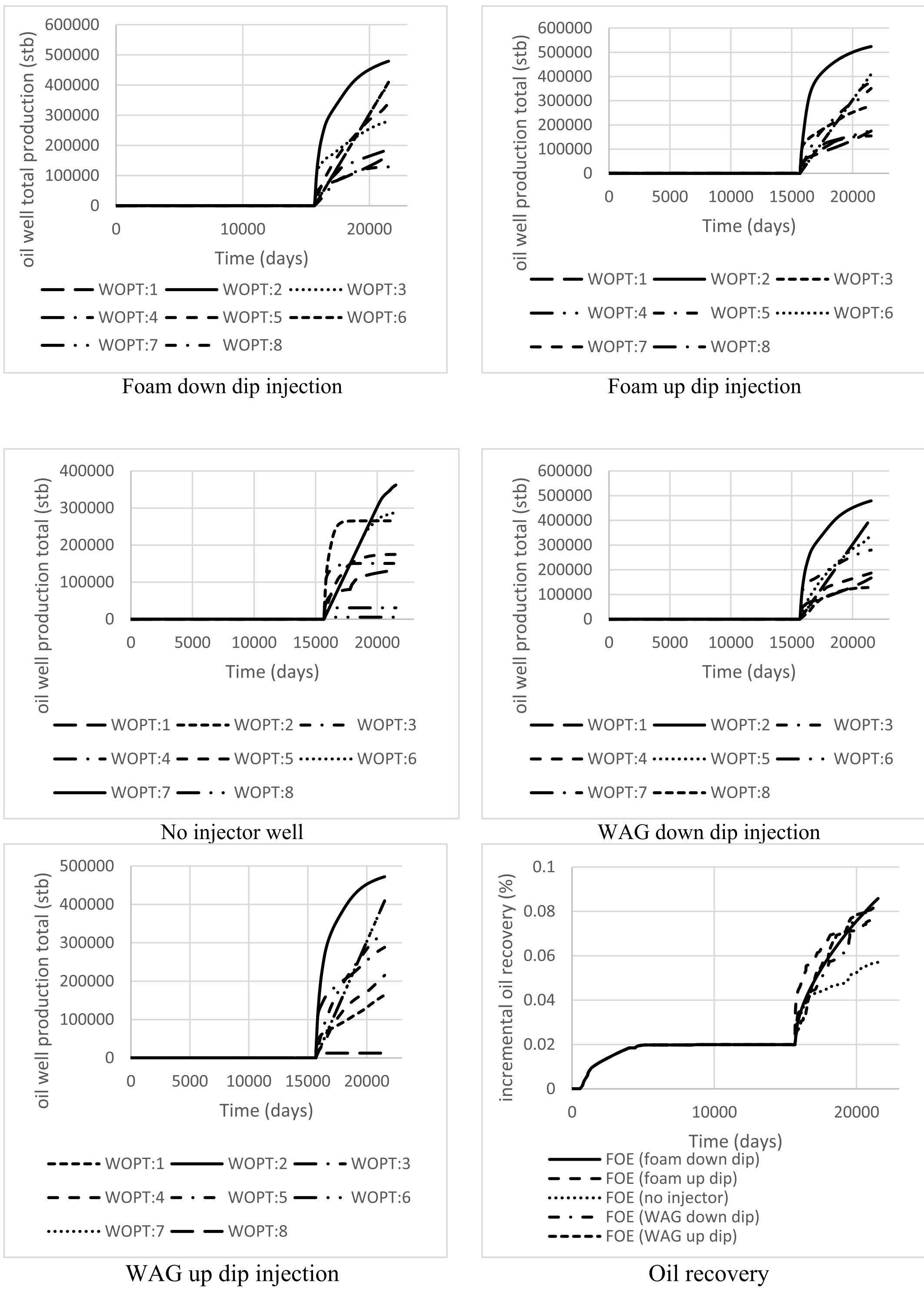


Fig. 12. Well oil production total during WAG up dip injection.

was bypassed or re located during injection. Further simulation studies can be done to ascertain the level of oil recovery when foam concentration is increased as foam effectiveness diminishes with the presence of oil.

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Glossary

Stb: stock tank barrel
WAG: water alternating gas
FOAMFSC: Foam mobility reduction dependence on foam surfactant concentration
FOAMFSO: Foam mobility reduction dependence on oil saturation
FOAMFSW: oam decay data as a function of water saturation
FOAMFCN: Foam mobility reduction dependence on foam surfactant concentration
FOAMFRM: Foam mobility reference reduction factor
WOC: water oil contact
GOC: gas oil contact
Scf: standard cubic feet.