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

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\section*{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
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 OOIP. 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 1

Oil rim uncertainties

<table>
<thead>
<tr>
<th>Parameter Range For The 15 uncertainties simulated</th>
<th>Units</th>
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<tbody>
<tr>
<td>Dip Angle</td>
<td>degrees</td>
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<tr>
<td>Gas Wetness (OGR)</td>
<td>stb/Mscf</td>
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<tr>
<td>Oil Column Height (Ho)</td>
<td>feet</td>
</tr>
<tr>
<td>M-factor (gas cap size) (m-factor)</td>
<td></td>
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<tr>
<td>Aquifer height to hydrocarbon thickness ratio (Aqf)</td>
<td></td>
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<tr>
<td>Horizontal permeability (Kx, Ky)</td>
<td>mD</td>
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<tr>
<td>Kv/Kh</td>
<td></td>
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<tr>
<td>Wellbore Diameter</td>
<td>feet</td>
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<tr>
<td>Oil Density</td>
<td>lb/ft.3</td>
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<tr>
<td>HGOC (Perforation with respect to the GOC)</td>
<td>feet</td>
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<tr>
<td>HWL (Horizontal well length)</td>
<td>feet</td>
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<tr>
<td>Oil Rate (Qo)</td>
<td>stb/day</td>
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<tr>
<td>Krw (Rel. perm. to water)</td>
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<td>GOR control (°Rsi)</td>
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<tr>
<td>BHP (Bottomhole Pressure)</td>
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<table>
<thead>
<tr>
<th>Parameter</th>
<th>Range</th>
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<td>2.5-7.5</td>
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<td>BHP (Bottomhole Pressure)</td>
<td>1500-2200</td>
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models from a wider range of uncertainties especially those neglected by authors which are reviewed later.

Design of experiments have been deployed to quantitatively assess 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 ratio, water cuts and pressures and no validation with production data have been discussed. The number of runs is a fraction 16/((2

### Table 2

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

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<th>Run No.</th>
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<th>Aqf</th>
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<th>Wellbore Diameter</th>
<th>Oil Density</th>
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The number of runs is a fraction 16/((2

### 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)
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. 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).

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### Table 3

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

Fig. 1. Oil production for model 8.

Fig. 2. Oil recovery factor for model 3.
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:

{\begin{align}
\text{Recovery Factor (} & = 11.4465 + 12.0662(\text{Dip Angle}) + 17.3848(\text{GOR}) - 42.522(\text{GOC}) + 47.9824(\text{Oil Rate}) - 3.3844(\text{Acfgl}) + 34.9484(\text{K}_h\text{K}_g) - 26.644(\text{K}_h) + 0.3896(\text{Wellbore Diameter}) + 45.8114(\text{Oil Density}) - 27.632(\text{HGOC}) - 14.216(\text{HWL}) - 21.052(\text{Oil Rate}) + 11.2064(\text{K}_h) - 17.307(\text{GOR}) - 6.0624(\text{BHP}) \\
\text{Recovery Factor (} & = 49.71483 - 12.8986(\text{Dip angle}) + 27.9174(\text{GOR}) - 11.5132(\text{K}_h) + 3.42685(\text{m factor}) + 27.20964(\text{Acfgl}) - 6.14772(\text{K}_h\text{K}_g) - 15.619075(\text{K}_h) - 5.44818(\text{Wellbore Diameter}) - 23.093(\text{Oil Density}) + 26.6046(\text{HGOC}) - 16.3465(\text{HWL}) - 16.3765(\text{Oil Rate}) + 36.9368(\text{K}_h) + 15.1330(\text{GOR}) - 85.3602(\text{BHP}) \\
\end{align}}

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 was 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.
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.

Recovery Factor \( (n_{max}) \) = 11.4465 + 12.0662(Dip) + 17.3848(OGR) – 42.522
\( (H_w) + 47.9824(m\text{Factor}) - 3.3584(Aquifer) + 34.9484(K_h-K_w) - 26.64(K_h-K_w) \)
\(- 0.3896(\text{Wellbore Diameter}) + 45.8114(\text{Oil Density}) - 27.632(\text{HGOC}) - 14.216(\text{HWL}) - 21.052(\text{Oil Rate}) + 11.2064(\text{K_w}) - 17.07(\text{GOR}) - 6.0624(\text{BHP}) \)

(3)

Recovery Factor \( (n_{max}) \) = 49.71483 + 12.88961(Dip) + 27.9174(OGR) – 13.1532(H_w) + 3.426585(m\text{Factor}) + 27.20964(Aquifer) – 6.14772(K_h-K_w) –
\( 0.15(\text{Wellbore Diameter}) - 25.0930(\text{Oil Density}) + 26.60462(\text{HGOC}) - 16.3405(\text{HWL}) - 16.3765(\text{Oil Rate}) + 36.9368(\text{K_w}) - 15.1330(\text{GOR}) - 85.3602(\text{BHP}) \)

(4)

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

Table 6
Simulation injection models.

<table>
<thead>
<tr>
<th>Reservoir type</th>
<th>Simulation models</th>
<th>Respective percentage oil recoveries</th>
</tr>
</thead>
<tbody>
<tr>
<td>Large gas cap large aquifer</td>
<td>3, 9</td>
<td>21.98, 17.36</td>
</tr>
<tr>
<td>Large gas cap small aquifer</td>
<td>4, 10</td>
<td>1.076, 28.271</td>
</tr>
<tr>
<td>Small gas cap large aquifer</td>
<td>6, 14</td>
<td>6.675, 8.622</td>
</tr>
<tr>
<td>Small gas cap small aquifer</td>
<td>5, 7</td>
<td>11.433, 15.905</td>
</tr>
</tbody>
</table>

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

Table 7
Foam property data.

<table>
<thead>
<tr>
<th>Description</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>FOAMADS Flc (lb/stb)</td>
<td>0</td>
</tr>
<tr>
<td>FOAMMOB Conc (lb/stb)</td>
<td>0.001</td>
</tr>
<tr>
<td>FOAMMOBQ Poil (psia)</td>
<td>1</td>
</tr>
<tr>
<td>FOAMMOBS Gas phase flow velocity</td>
<td>0</td>
</tr>
<tr>
<td>FOAMDCYW Lcl Sw</td>
<td>0</td>
</tr>
<tr>
<td>FOAMDCYO Slo</td>
<td>1</td>
</tr>
<tr>
<td>FOAMROCK Adsorption index</td>
<td>2</td>
</tr>
</tbody>
</table>

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

### Table 8

<table>
<thead>
<tr>
<th>WAG CYCLE 1</th>
<th>WAG CYCLE 2</th>
<th>WAG CYCLE 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Run No.</td>
<td>Base oil RF</td>
<td>incrmt WAG</td>
</tr>
<tr>
<td></td>
<td></td>
<td>up dip injtn</td>
</tr>
<tr>
<td></td>
<td></td>
<td>down dip injtn</td>
</tr>
<tr>
<td></td>
<td></td>
<td>incrmt WAG</td>
</tr>
<tr>
<td></td>
<td></td>
<td>up dip injtn</td>
</tr>
<tr>
<td></td>
<td></td>
<td>down dip injtn</td>
</tr>
<tr>
<td>Model 3</td>
<td>21.98</td>
<td>4.986</td>
</tr>
<tr>
<td>Model 4</td>
<td>1.076</td>
<td>30.174</td>
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<td>Model 5</td>
<td>11.43</td>
<td>1.315</td>
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<tr>
<td>Model 6</td>
<td>6.675</td>
<td>6.838</td>
</tr>
<tr>
<td>Model 7</td>
<td>15.91</td>
<td>22.675</td>
</tr>
<tr>
<td>Model 9</td>
<td>17.36</td>
<td>2.91</td>
</tr>
<tr>
<td>Model 10</td>
<td>28.27</td>
<td>14.479</td>
</tr>
<tr>
<td>Model 14</td>
<td>8.622</td>
<td>15.548</td>
</tr>
</tbody>
</table>

Fig. 6. Oil recovery from WAG injection (cycle-2).
WAG injection. The foam being 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 unswept 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. 7. Oil recovery from models under WAG injection (Cycle-2).

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

<table>
<thead>
<tr>
<th>reservoir</th>
<th>Up dip oil recovery</th>
<th>Down dip oil recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>@ 50,000 Mcf/day</td>
<td>32.94%</td>
</tr>
<tr>
<td></td>
<td>@ 100,000 Mcf/day</td>
<td>33.66%</td>
</tr>
<tr>
<td></td>
<td>@ 150,000 Mcf/day</td>
<td>36.17%</td>
</tr>
<tr>
<td>7</td>
<td>@ 50,000 Mcf/day</td>
<td>47.07%</td>
</tr>
<tr>
<td></td>
<td>@ 100,000 Mcf/day</td>
<td>60.29%</td>
</tr>
<tr>
<td></td>
<td>@ 150,000 Mcf/day</td>
<td>68.64%</td>
</tr>
<tr>
<td>10</td>
<td>@ 50,000 Mcf/day</td>
<td>63.70%</td>
</tr>
<tr>
<td></td>
<td>@ 90,000 Mcf/day</td>
<td>73.36%</td>
</tr>
<tr>
<td></td>
<td>@ 150,000 Mcf/day</td>
<td>82.63%</td>
</tr>
<tr>
<td>14</td>
<td>@ 100,000 Mcf/day</td>
<td>41.23%</td>
</tr>
<tr>
<td></td>
<td>@ 150,000 Mcf/day</td>
<td>41.24%</td>
</tr>
<tr>
<td></td>
<td>@ 200,000 Mcf/day</td>
<td>50.16%</td>
</tr>
</tbody>
</table>

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).

<table>
<thead>
<tr>
<th>Prediction scenario (stb)</th>
<th>WELLS</th>
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</thead>
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<tr>
<td></td>
<td>1</td>
</tr>
<tr>
<td>No injector</td>
<td>134,763.5</td>
</tr>
<tr>
<td>Down dip WAG injection</td>
<td>151,064.9</td>
</tr>
<tr>
<td>Up dip WAG injection</td>
<td>163,854.9</td>
</tr>
<tr>
<td>Foam up dip injection</td>
<td>174,786.0</td>
</tr>
<tr>
<td>Foam down dip injection</td>
<td>167,061.1</td>
</tr>
</tbody>
</table>
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

<table>
<thead>
<tr>
<th>Recovery type</th>
<th>Recovery (stb)</th>
<th>Recovery (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural (no injector)</td>
<td>1,410,436</td>
<td>5.9</td>
</tr>
<tr>
<td>WAG up dip injection</td>
<td>2,302,678.618</td>
<td>8.35</td>
</tr>
<tr>
<td>WAG down dip injection</td>
<td>1,747,589.23</td>
<td>7.94</td>
</tr>
<tr>
<td>Foam Up dip injection</td>
<td>2,444,133.34</td>
<td>8.57</td>
</tr>
<tr>
<td>Foam down dip injection</td>
<td>2,385,218</td>
<td>8.56</td>
</tr>
</tbody>
</table>

Table 11
Summary of oil recovery from injection schemes.

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

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was bypassed or relocated 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.

References


Glossary

Stb: stock tank barrel

WAG: water alternating gas

FOAMSCR: Foam mobility reduction dependence on foam surfactant concentration

FOAMMRC: Foam mobility reduction dependence on oil saturation

FOAMDFC: 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.