Optimization of Production from Thin Oil Rim Reservoirs Through Horizontal Wells

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Abstract: **Understanding oil rim reservoir production dynamics is critical to successful development of thin oil rims. The interplay of subsurface factors and production constraints determine the dynamics of oil Rim reservoir production. Therefore, in this work, the impact of a range of subsurface uncertainty on oil rim recovery was captured by employing the Plackett-Burman Design of Experiment (DOE) technique. The methodology involves a detailed oil rim simulation study. By employing the classical numerical reservoir simulation equation, assuming a negligible difference in fluid potential and applying material balance principle, the response surface model or proxy developed for cumulative oil recovery (Np) was combined with the cone breakthrough time equation and forms an integral part of the model. The model was developed through proxy model analysis of applying the principle of Nodal analysis to graphically combine gas-oil contact and oil-water contact respectively; with a view to controlling gas and water coning phenomena in gas-oil-water reservoir system. The result was compared with an existing correlation with field data obtained from the Niger Delta oil field. The models are simple for fast calculations for reservoirs with thin oil zones sandwiched between gas cap and bottom water. It is concluded that the developed models can be used as a tool to make a pass assessment in the development of oil rim reservoirs anticipated to experience water and gas coning during production.**

Keywords**: Optimum Oil Recovery; Thin Oil Rim Reservoirs; Plackett-Burman Design of Experiment; Nodal Analysis, Niger Delta field**

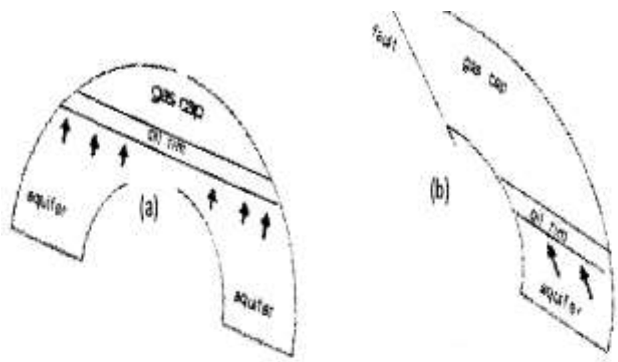
I. INTRODUCTION

Many oil reservoirs have gas-cap and/or water support. The structure of the reservoir may be dome-shaped with the oil zone sandwiched between the gas cap and bottom water, or sloping with edge water (see Figure l.1) (Okoro, 2018). If a wellbore draws oil or gas from an area near the gas or water zone, the gas and/or water can be drawn into the wellbore due to coning because gas and water are generally less viscous than oil, and thus flow more easily than oil. This phenomenon occurs particularly at high production rates where gravity effects are too small to counteract the effects of viscosity ratio, creating problems due to excessive gas or water production compared with the oil production (Onuka and Okoro, 2019).

If the water contains salts such as sodium chloride, these can corrode production facilities such as separators and connecting pipe work. The produced fluids wilt also have to be separated before transporting to the refinery. The reduction in oil production and increased operating expenses all lead to reduced revenue. Unfortunately, such a situation cannot be avoided if the oil is being drawn from near the oil-water or gas-oil contacts, and particularly when the oil-bearing zone is thin (Onuka and Okoro, 2019).

For reservoirs with both gas cap and an aquifer, the more valuable resource is produced before the gas from the overlying gas cap. This is because (i) as oil is produced, the reservoir pressure drops and gas comes out of solution, reducing the volume of oil that can be produced, and (ii) as 1the gas cap pressure is lowered, the oil can move upwards into the gas cap. There the saturation oil increases from zero, but some of this oil will remain trapped and will not be recovered because of the capillary forces acting within the reservoir porous matrix, thereby reducing overall recovery. These factors also have negative financial implications, for cases in which the oil column is thin (50ft), development and production of the oil column present additional challenges (Okoro, 2020; Okoro, 2018).

Figure 1.1: Bottom and edge water. a) Dome shaped reservoir with bottom water drive. b) Truncated anticline with edge water drive (Okoro, 2020).



Generally, the production of oil rims is planned to be as rapid as possible. Unfortunately, when the oil is produced prior to the overlying gas, production is not always trouble free because of gas and/or water coning (Onuka & Okoro, 2019). This project investigates the problems of thin oil rim reservoirs and presents the successful current reservoir management practices to be carried out.

An oil rim is a thin oil column in a reservoir located between a large gas cap and an aquifer. Its production mechanism is complicated due to a very thin oil zone. One of the most challenging tasks in such a reservoir is to keep the gas oil contact (GOC) and oil water contact (OWC) stable during production because drawdown causes their movement. Drawdown is also the main cause for gas and water coning. For thin oil rim reservoirs, the key force balance is between the gas cap and aquifer expansion, and the fluid withdrawal by well production, in addition to the capillary and gravitational forces (Okoro, 2018). The understanding of the force balance in the reservoir will lead towards a better optimization of reservoir oil and gas production, achieving a higher recovery factor, and generating a good investment plan.

These factors made the necessity to develop thin oil rim reservoirs by implementing horizontal wells, in addition to vertical wells (Mixed Development Strategy), to improve the oil recovery in one hand, and to reduce water and gas coning problems. One of the main reasons for coning is pressure drawdown. A vertical well exhibits a large pressure drawdown near the wellbore, whereas horizontal well exhibits minimum pressure drawdown, thus horizontal wells provide options whereby pressure drawdown can be minimized, coning tendencies can be minimized, and high oil production rates can be achieved (Onuka and Okoro, 2019). For a vertical well, the majority of the pressure drawdown is consumed near the wellbore. Therefore, there is a big drawdown around the wellbore in a vertical well. In the case of horizontal wells, the pressure drop is fairly uniform throughout the reservoir near the wellbore; an extra pressure drop is observed. This pressure drop is, however, very small as compared to that around a vertical wellbore. For horizontal wells, due to low pressure drawdown, one expects a high oil production rate without water coning. In a reservoir with bottom water or top gas, rising water and downward movement of the gas cap can be controlled to obtain the best possible sweep of the reservoir. This is also called water cresting (Okoro, 2020). With proper operating procedure, the bottom water drive for horizontal wells behaves very similar to a water-flood for vertical wells, resulting in very high recovery. A horizontal well provides an option not only to enhance initial oil-production rates, but also to obtain maximum possible ultimate reserves in a shorter time than a vertical well. The development and application of horizontal wells drilling technology is causing a revolution in the petroleum exploration and exploitation industry (Onuka & Okoro, 2019).

II. CONING

Coning is the mechanism whereby gas or water moves toward the production interval of an oil well in a cone or crest-like form created by fluid off take (Kromah and Dawe, 2008). It is caused by the pressure drawdown within the oil column close to the wellbore being sufficiently large to overcome viscous and gravity forces and draw the water or gas into the well. As the flowrate increases, the cone height also increases until at a critical rate, the cone becomes unstable and water, or gas, is drawn into the wellbore above the oil-water contact, or below the gas-oil contact (see Figure 2).

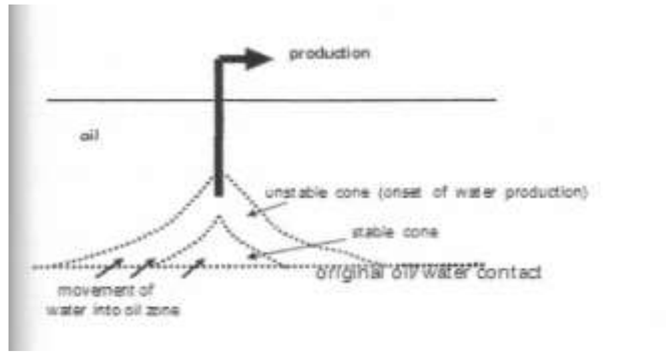


Figure 2: Stable and unstable cones

This premature water or gas breakthrough is often referred to as coning on vertical flow, or cresting on horizontal flow. While coning involves the localized movement of gas or water towards the well, cresting involves the localized movement of gas or water along a significant, if not, the entire length of a horizontal

Horizontal wells development technology can increase well production by expanding well drainage area, improving the development benefit of the oilfield. The horizontal well technique is applicable to the whole process of oilfield development. In the early development stage of the oilfields, horizontal well has a high productivity, fast construction production, less investment and advantage characteristics of quick recovery; while in the middle-later period of the oilfields, vertical wells development has poor potential benefits, the horizontal wells can be used as a cost-effective tapping of the ways and means for developing oilfields because of its larger oil drainage area, small producing pressure drop, restraining cut rising, improving well productivity and other advantages. Horizontal wells have been widely applied to thin reservoir, gas cap reservoir, edge and bottom. water reservoirs, fractured reservoirs, heavy oil reservoirs, and low permeability reservoir. The development effect of the oilfield which used horizontal wells technology was well improved.

Narrow oil ring reservoir with big gas cap is one of the complex reservoirs, a certain proportion of the world has been found in various types of reservoirs. Such reservoirs have this particularity: the distribution relationship of oil, gas and water is complex; The strata have a certain inclination, and reservoir distribution recognize uncertainty; the exploitation of reservoir is difficult because gas cap channeling and edge water coning are easy to split the narrow oil ring. It is difficult to efficiently develop narrow oil ring with big gas-cap reservoir for improving oil recovery. This work is based on a texts mining information in thin oil rim and pancake-type reservoir, to study the feasibility of horizontal wells to improve the narrow oil ring with big gas-cap reservoirs'.

III. METHODOLOGY

Oil Rim Simulation

To achieve optimum oil recovery from thin oil rim reservoirs, efforts must be made to avert or at least minimize the coning tendencies. To deepen understanding of oil rim recovery mechanism and improve predictive abilities, a simulation model has been developed and a series of sensitivities performed. The aim of this simulation study is to

1. Develop a correlation for oil rim ultimate recovery (UR) over a range of subsurface uncertainties
2. Apply the developed correlation in the determination of cone breakthrough time.

Coning

Coning is a production problem in which gas-cap gas or bottom water infiltrates the perforation zone in the near-wellbore area and reduces oil production. Gas coning is distinctly different from, and should not be confused with, free-gas production caused by a naturally expanding gas cap. Likewise, water coning should not be confused with water production caused by a rising water/oil contact (WOC) from water influx. Coning is a rate-sensitive phenomenon generally associated with high producing rates. Strictly a near-wellbore phenomenon, it only develops once the pressure forces drawing fluids toward the wellbore overcome the natural buoyancy forces that segregate gas and water from oil.

Derivation of Equation

$$\nabla\left(\beta_c \frac{KK_{rw}}{\mu_o B_o}\nabla\varphi_o\right)+\frac{Q_o}{V_b}=\frac{1}{5.615}\frac{\partial}{\partial t}\left(\frac{\emptyset S_o}{B_o}\right) \text{..................} 3.1$$

The following assumptions were applied to the numerical reservoir simulation equation stated above:

1. The effect of potential gradient is negligible i.e. $V\varphi_a$, = 0
2. Water saturation remains at the irreducible water saturation, S1, which implies that S_o = I - S_{wi} and the reservoir is undergoing single phase flow
3. The movement of oil and water in the oil, water and rock due to reservoir voidage and pressure drop due to gravity.

$$\frac{Q_o}{V_b}=\frac{(1-S_{wi})}{5.615}\emptyset\left[-B_o^{-2}\frac{\partial B_o}{\partial t}\right] \text{------------------} 3.2$$

$$\frac{Q_o}{V_b}=\frac{(1-S_{wi})}{5.615}\emptyset\left[-B_o^{-2}\frac{\partial B_o}{\partial P}\right]\frac{\partial P}{\partial t} \text{------------------} 3.3$$

Applying assumption 1, 2, and 3 and expanding the differential term at the RHS assuming constant porosity (homogenous reservoir) gives:

But considering the pressure drop due to gravity which arises from density difference between oil and water

$$C_t=-\frac{1}{B_o}\frac{\partial B_o}{\partial P} \text{..................} 3.4$$

Therefore

$$\left[-B_o^{-2}\frac{\partial B_o}{\partial P}\right]=\frac{C_t}{B_o} \text{..................} 3.5$$

Substitute equation 3.5 into equation 3.3 gives the following:

$$\frac{Q_o}{V_b}=\frac{(1-S_{wi})}{5.615}\emptyset\frac{c_t}{B_o}\frac{\partial P}{\partial t} \text{..................} 3.6$$

Separating variables and integrating both sides gives:

$$\frac{V_b(1-S_{wi})}{5.615}\emptyset\frac{c_t}{B_o}\times\Delta P=Q_o\times t \text{..................} 3.7$$

$$\Delta P=\Delta\rho g h_{wc} \text{..................} 3.8$$

n field unit, it becomes

$$\Delta P=32\Delta\rho h_{wc} \text{..................} 3.9$$

Considering oil and water, we have

$$\Delta P=32\times(\rho_w-\rho_o)h_{wc} \text{..................} 3.10$$

ubstituting equation 3.10 into equation 3.7, we get

$$\frac{V_b(1-S_{wi})}{5.615}\emptyset\frac{c_t}{B_o}\times 32\times(\rho_w-\rho_o)h_{wc}=Q_o\times t \text{..................} 3.11$$

rom general material balance

$$\int_o^t Q_o dt=\frac{V_b}{5.615}\int_o^t\frac{d}{dt}\left(\frac{\emptyset S_o}{B_o}\right)=\frac{V_b}{5.615}\left[\frac{\emptyset S_o}{B_o}-\frac{\emptyset S_{oi}}{B_{oi}}\right] \text{..................} 3.12$$

rom the above equation, it can be deduced that

$$N_p=\frac{V_b\emptyset(1-s_{wi})}{5.615B_o}-N \text{..................} 3.13a$$

$$N_p+N=\frac{V_b\emptyset(1-s_{wi})}{5.615B_o} \text{..................} 3.13b$$

Because our sign convention is negative for production, the variable N is negative. This differs from the sign convention used in Classical reservoir engineering, where production is positive.

Substituting equation 3.13b into equation 3.11, making breakthrough time the subject, for Oil/Water system will yield:

$$t_{ow} = \frac{32(\rho_w - \rho_o)c_t h_{wc}}{Q_o} \times \left[N_p + \left(\frac{7758Ah\emptyset(1 - s_{wi})}{B_{oi}}\right)\right] \ldots\ldots\ldots 3.14$$

And for oil/gas system, is given as

$$t_{og} = \frac{32(\rho_o - \rho_g)c_t h_{gc}}{Q_o} \times \left[N_p + \left(\frac{7758Ah\emptyset(1 - s_{wi})}{B_{oi}}\right)\right] \ldots\ldots\ldots 3.15$$

The following assumption was also made

$$h = pay\ thickness = h_{wc} + h_{gc} \ldots\ldots\ldots 3.16$$

$$a_{10} = 0.000072274$$

$$a_{11} = 0.471660688$$

IV. RESULTS AND DISCUSSION

Modeling the oil rim reservoir with horizontal well placement, the horizontal well plan was perforated at the centre or mid-rim thickness, that is, equidistance from gas-oil contact and oil- water contact. Fig. 4.1 through fig. 4.5 indicates the effect of different properties on the thin oil rim performance with horizontal well placement scheme.

Six oil rim reservoirs from the Niger Delta field within the range of 10ft -50ft was selected. Below is the summary table of the predicted results from the developed model. Equation 3.17 and 3.18 were used to calculate the breakthrough time and oil recovery from the thin oil reservoirs.

Table 4.1 Summary of the results from the developed model

Reservoir	Ho	m-fac	Aq-fac	Kv/Kh	Oil API	HGOC	HWL	Q	ρ_o	Np, (mmstb)	Tb, days
A1	28	2.1	15	0.01	30.58	22.5	1200	3000	54.48	1.05	411
A2	30	0.6	15	0.01	30.03	24.75	1200	2500	54.66	1.08	577
A3	38	1.6	7	0.01	30.21	26.25	1200	5000	54.60	1.22	331
A4	40	1.0	7	0.01	37.96	28.50	1200	1500	52.10	1.42	1665
A5	46	1.3	2	0.01	31.89	28.50	1200	2500	54.04	1.22	814
A6	50	0.5	15	0.01	31.52	31.5	1200	5000	53.54	1.49	502

Table 4.2 shows the permeability and thickness effect of the thin oil rim reservoir

Oil rim thickness (ft)	Oil Recovery, MMstb					
	100 mD	250 mD	500 mD	750 mD	1000 mD	1250 mD
10	0.1	0.13	0.145	0.2	0.28	0.33
20	0.28	0.34	0.51	0.62	0.78	0.9
30	0.66	0.71	0.93	1.05	1.20	1.65
40	1.00	1.08	1.35	1.60	1.98	2.40
50	1.20	1.30	1.72	2.00	2.40	3.00

Table 4.3 shows the aquifer effect on the thin oil rim reservoir

Oil rim thickness (ft)	Oil Recovery, MMstb		
	Weak Aquifer	Ref. Case	Strong Aquifer
10	0.22	0.3	0.4
20	0.57	0.7	0.93
30	0.94	1.32	1.70
40	1.47	2.00	2.72
50	1.80	2.40	3.31

Table 4.4 shows the permeability anisotropic effect of the thin oil rim reservoir

Oil rim thickness (ft)	Oil Recovery, MMstb		
	$K_v/K_h = 0.1$	$K_v/K_h = 0.01$	$K_v/K_h = 0.001$
10	0.26	0.27	0.275
20	0.62	0.67	0.71
30	1.10	1.21	1.36
40	1.80	1.98	2.09
50	2.13	2.42	2.68

Table 4.5 shows the oil viscosity effect of the thin oil rim reservoir

Oil rim thickness (ft)	Oil Recovery, MMstb				
	0.3 cp	0.4 cp	0.6 cp	0.8 cp	1.3 cp
10	0.2	0.22	0.3	0.38	0.42
20	0.58	0.62	0.71	0.86	0.99
30	0.95	1.08	1.2	1.60	1.82
40	1.5	1.7	1.92	2.36	2.79
50	1.7	2.0	2.4	2.88	3.42

Table 4.6 shows the gas cap size (m-factor) effect of the thin oil rim reservoir

Oil rim thickness (ft)	Oil Recovery, MMstb				
	M = 0.2	M = 0.5	M = 1	M = 2	M = 5
10	0.382	0.34	0.25	0.24	0.24
20	1.00	0.82	0.71	0.71	0.71
30	1.88	1.52	1.30	1.28	1.30
40	2.82	2.34	1.9	1.98	2.00
50	3.50	2.90	2.42	2.38	2.50

From Fig. 4.3, it shows that high Ky's (vertical permeability) increases the chances of water coning and reduces oil recovery. This is the reason while recovery decreases with increasing permeability anisotropy. It is observed that placing the well at the mid-rim is a better placement for the oil rim thickness. The scenario delays gas coning phenomena, whereas, when the well is placed closer to the Gas-Oil Contact, the oil recovery will be low due to gas coning problem.

Sensitivities on Oil Column Thickness (Ho)

Oil rim thickness affects the coning effect, which is gas or water entering into the well perforations. An increase in the thickness of the oil rim reservoir leads to increase on the distance of the gas-oil contact and oil-water contact Therefore, the advancement of gas or water coning will take longer time to breakthrough.

The thickness of this oil rim reservoir also helps in detecting the STOIIP which can be used for the economic analysis of the incremental benefits of the horizontal drilling scheme.

The aquifer strength is model with respect to aquifer length and keeping other properties constant. From fig. 4.4 it is observed that a stronger aquifer will have a higher oil recovery from the oil rim thickness. Whereas, a weak aquifer will not have a good support to the oil rim reservoir, therefore, it results to a lower oil recovery.

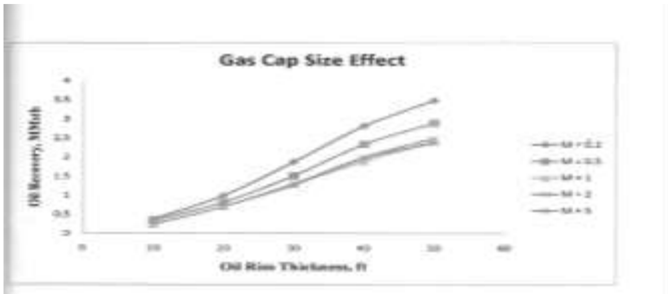


Fig. 4.1 Effect of Gas Cap Size in an oil rim reservoir

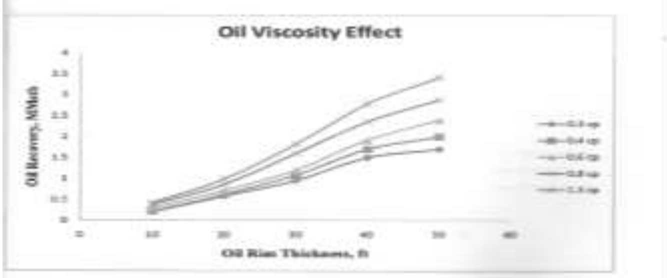


Fig. 4.2 Effect of oil viscosity in an oil rim reservoir

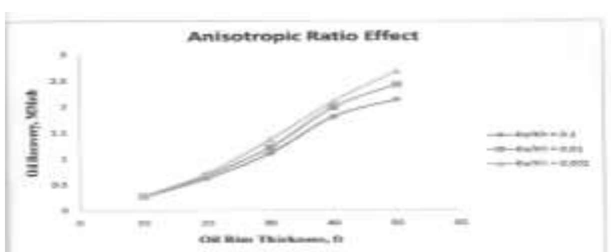


Fig. 4.3 Effect of permeability anisotropy in an oil rim reservoir

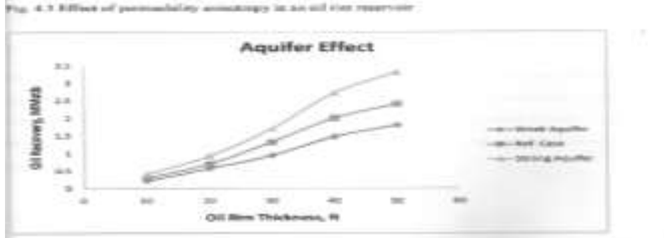


Fig. 4.4 Effect of aquifer strength in an oil rim reservoir

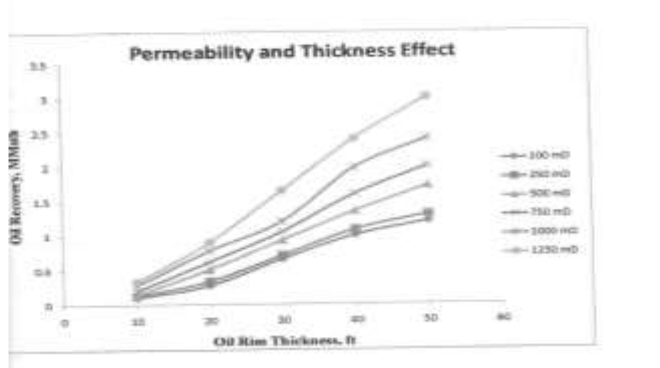


Fig. 4.5 Effect of permeability in an oil rim reservoir

Model Validation

The proxy models of estimating N and tb was compared with the developed semi-analytical method of estimating N_p and t_b. Fig. 4.1 to 4.5 shows that the N_p estimated from the proxy model compare favourably with that of the semi-analytical method with an R Square of 0.96447. It also shows a perfect match in the t_b estimated from the proxy model and that estimated from the semi- analytical method with an R Square of 0.9995.

V. CONCLUSION

From the results of the oil rim model simulations, the following conclusions are made:

1. Oil rim recovery is strongly dependent on the following subsurface parameters; oil rim thickness, aquifer factor, permeability anisotropy, oil viscosity and rn-factor. The aquifer factor and rn-factor constitute the main reservoir energy. Oil rim recovery is also a function of oil rim movement, well placement and reservoir pressure. However, with ultrathin oil rims of thickness less than 30 ft, well placement makes little or no impact onoil recovery.
2. Comparatively, incremental benefit of horizontal well planning is higher than that of vertical well planning. This is as a result of delay in gas and water coning effect using horizontal well planning scheme.
3. Horizontal well planning scheme improves oil rim recovery by a factor of about 15% of (stock tank oil in place (STOIIP) if effective well planning is achieved.
4. The model analysis done indicates that the subsurface uncertainties that has the most effect on cumulative production which is used to model the breakthrough time model includes; permeability, API, horizontal length, oil flow rate, and permeability anisotropy.
5. Breakthrough time for oil/gas/water system was developed for horizontal well by applying DOE technique and material balance approach.

Based on these findings, it is recommended for a further study on subsurface uncertainty analysis be done and incorporated into the thin oil rim mathematical equations (models).

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