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Use of Horizontal Wells as an Effective Production Strategy for Thin Oil Rim Reservoirs

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Abstract

Oil production from thin oil rims bounded at the top with a large gas cap and at the bottom with an aquifer is often very challenging to produce. Some production challenges include low oil recovery efficiency, early water breakthrough, high water cut and high gas oil ratios. Several production techniques have been suggested but one effective method has been production using horizontal wells instead of the conventional vertical wells. In this work, a simulation approach is used to study oil recovery efficiency and water cut from an offshore Niger Delta thin oil rim with several faults. The simulation work was conducted using three vertical wells and three horizontal wells. The study results showed that production using horizontal wells perform better than vertical wells in thin oil rims. The use of horizontal wells delayed water breakthrough time, improved oil recovery efficiency and reduced water cut. It was observed that increasing the length of the horizontal wells optimally improved oil recovery efficiency. But since the length of horizontal wells has a limit due to technical constrains, it is recommended that the length of horizontal wells be extended to at least one-third of the drainage length to ensure maximum oil recovery efficiency.

Keywords*: Coning; Horizontal well; Vertical well; Recovery efficiency; Water-cut.*

1. Introduction

Thin oil rim reservoir is a reservoir in which the pay zone is sandwiched between an aquifer and a gas cap with limited thickness. Regardless of the thickness of a thin oil rim reservoir, it contains substantial volumes of hydrocarbon [1-2] but poses several production challenges. One of such challenges is water and gas coning which has not only proved detrimental to ultimate oil recovery, but has impacted adversely on the economics of the entire development process of thin oil rims. Thus, a successful development of thin oil rim reservoir entails strategic plans towards accelerating oil recovery prior to coning [3]. In this work, a simulation approach is used to demonstrate how thin oil rim reservoirs can be effectively produced using horizontal wells.

Coning is another challenge encountered while producing oil from thin oil rims. Coning is often referred to as the premature water or gas breakthrough in vertical flow, or cresting in horizontal flow. While coning involves localized movement of gas or water towards the well, cresting involves localized movement of gas or water along a significant or entire length of a horizontal well. Bayley-Haynes [4] showed that accelerating oil recovery prior to water and gas coning can be achieved using horizontal wells. Generally, horizontal wells are proposed alternatives to vertical wells in optimal development of thin oil rim reservoirs because it minimizes water conning and gas cusping by reduction in drawdown. Drawdown reduction also alleviates sand production problems and drains a larger volume of reservoirs since some parts of the reservoir are in contact with the well's path.

Thin oil reservoirs have typical oil thickness ranging from less than 30ft up to 90ft, usually overlain by gas cap and underlain by water [5]. The hydrocarbon columns in thin oil rim reservoirs are mainly in the capillary transition zone due to their limited thickness, regardless of the type of rock and inherent properties. The average high water saturation transition zones together with underlain aquifers and overlain gas caps create complex flow dynamics in such reservoirs.

Concurrent reservoir development strategy for fields with a small gas cap and large aquifer is another technique that has been deployed. This method involves maximizing oil production by blowing down the gas cap during the initial production phase, provided a strong aquifer exists with a small gas cap (m< 0.2). If the gas cap is excessive, it may be futile to try preventing gas coning as this would either limit oil rates or require non-optimal placement of perforation, leading to re-completions later in order to capture the remaining oil.

Another suggested conventional strategy to develop thin oil rims is to complete the well typically in between the fluid contacts [6]. Two options in producing such reservoirs are crestal vertical completion in the gas-cap for reservoirs with small gas-cap or either vertical or horizontal completion at the gas/oil interface for reservoirs with moderate or large gas-cap. The horizontal drain hole is placed in the oil column at a predetermined standoff from the GOC. Horizontal completion at the gas/oil interface for reverse coning can be applied to saturated reservoirs with small or large gas-cap. In this option, horizontal wells are completed near the gas/oil interface to improve recovery. The option is effective in large gas-cap reservoirs where displacement of oil in the gas-cap is thought undesirable. A dual horizontal well completion, one in the oil zone and the other in the water zone to reduce water coning in horizontal wells is also possible.

Vertical movement of water or gas across the bedding plane near the wellbore occurs when the viscous forces around the wellbore exceed the gravity forces due to density difference between the fluids. Semi analytical models of estimating critical rate and optimum horizontal well placement to control coning tendencies in oil rim reservoirs have been developed [7]. The model was developed by applying the principles of nodal analysis to graphically combined gas-oil reservoir and oil-water reservoir systems with the aim of controlling water and gas coning phenomena. The analytical solution can be used to determine the optimum wellbore penetration interval of a well that partially penetrates an oil reservoir from its top.

In horizontal wells, the pressure profile is fairly uniform along the horizontal portion of the wellbore, with slightly lower pressure, hence larger pressure drawdown around the heel. In this case, the lower pressure drawdown increases the tendency for gas and/or water to cone more rapidly. The size and shape of the cone formed is related to the magnitude and extent of the pressure drop, with vertical wells forming tall narrow cones and horizontal wells forming flat, wide cones or crests. The production strategy for horizontal wells in thin oil columns is normally to place the well near the gas-oil-contact and allow the aquifer to drive the oil upwards to minimize oil losses [8].

The principal application of horizontal well technology is to improve hydrocarbon recovery from water and/or gas-cap driven reservoirs. The advantages of using horizontal wells over vertical wells include the large capacity to produce oil at the same drawdown, and a longer water breakthrough time at a given production rate [9]. Thus, developments in horizontal well technology and performance during the past years have placed horizontal wells among the commercially viable well-completion techniques [10]. Joshi [8] showed that when there is no fluid influx into a reservoir across its boundaries, pseudo-skin factors can be used to determine the productivity improvement expected from horizontal well completions. The behavior of water drive reservoirs poses a more complicated problem, and investigation of the productivity of wells operating under such conditions requires a different approach [10].

2. Method of study

Three cases of horizontal wells, W1, W2 and W3 were used to demonstrate how effective horizontal wells drain oil from thin oil rims compared to vertical wells. The wells are located in the same Niger Delta offshore field and were drilled to produce oil from the same reservoir. Information about the reservoir and its properties were obtained through a drilled pilot hole and through well logs. A summary of the properties of the three wells are given in Table 1.

Table 1. Summary of the Wells, reservoir and fluid properties

Parameters	Well Name		
	W1	W2	W3
Drainage Length, y_e [ft]	3000	3000	2640
Drainage Width, x_e [ft]	1700	2400	1320
Length of horizontal well, L [ft]	1100	1200	1000
Wellbore radius, r_w	0.51	0.51	0.51
Oil Column, h [ft]	22	16	25
Formation porosity, φ	0.32	0.32	0.32
Average horizontal Permeability, k_h [mD]	500	500	500
Average vertical Permeability, k_v [mD]	400	400	400
End-point oil relative permeability, $k_{ro@S_{wc}}$	0.72	0.72	0.72
End-point H_2O relative permeability, $k_{rw@S_{or}}$	0.4	0.4	0.4
Connate water saturation, S_{wc}	0.35	0.35	0.35
Residual oil saturation, S_{or}	0.3	0.3	0.3
Total compressibility, [1/psia]	3e-6	3e-6	3e-6
Oil viscosity, μ_o [cP]	0.37	0.37	0.37
Water viscosity, μ_w [cP]	0.53	0.53	0.53
Oil formation volume factor, B_o [rb/Stb]	1.33	1.33	1.33
Water formation volume factor, B_w [rb/Stb]	1.0	1.0	1.0
Oil density, ρ_o [lb/cuft]	51.8	51.8	51.8
water density, ρ_w [lb/cuft]	67	67	67
Liquid Production Rate, Q [Stb/day]	725	1015	1000

Drilling the first 1100ft long horizontal well (W1) was very successful with thin productive sand thickness of 22ft, and it exists between a major and minor fault. Upon completion of well W1, production started on August 10, 1999 at a rate of 729 barrel of fluid per day with a water cut of 5.8%. Well W1 was separated from W2 and W3 by a fault. A month after W1 was put to production, water-cut increased after withdrawing fluids at rates above 1200 barrels per day. The second well W2 of 1200ft long was drilled in the same reservoir and it penetrated a 16ft oil column of sand. It produced at a water-cut of 88% which remained constant for six months; hence the high water-cut musts have resulted from coning. In practice, horizontal wells were used to produce the field, but for the purpose of comparison the study assumed an equivalent vertical well of the same wellbore radius with the horizontal well, producing with the same liquid rate and draining from the same reservoir sand. A third well W3 was later drilled in the same reservoir.

3. Breakthrough time

Papatzacos [11] proposed a methodology that is based on semi-analytical solutions for time development of a gas or water cone and simultaneous gas and water cones in an anisotropic, infinite reservoir with a horizontal well placed in the oil column. The breakthrough time is given as:

$$t_{BT} = \frac{22755 h\varphi\mu_o}{k_v \Delta\rho} t_{DBT} \quad (1)$$

The dimensionless breakthrough time for $q_D < 0.4$ is given as:

$$t_{DBT} = 1 - (3q_D - 1)\, ln\left(\frac{3q_D}{3q_D - 1}\right) \quad (2)$$

For $q_D \geq 0.4$

$$ln\, t_{DBT} = -1.7179 - 1.1633\, ln\, q_D + 0.16308(ln\, q_D)^2 - 0.046508(ln\, q_D)^3 \quad (3)$$

where

$$q_D = \frac{20333.66\mu_o B_o Q_o}{L h \Delta\rho\sqrt{k_v k_h}} \quad (4)$$

The equivalent breakthrough time in vertical well is computed as follow:

$$t_{BT} = \frac{20335\varphi\mu_o h}{k_v \Delta\rho(1+M^{\alpha})} t_{DBT} \tag{5}$$

The mobility ratio is defined in terms of end-point relative permeability and viscosity, and it is given as:

$$M = \left(\frac{\mu_o}{\mu_w}\right)\left(\frac{k_{rw@S_{or}}}{k_{ro@S_{wc}}}\right) \tag{6}$$

Such that $\alpha = 0.5$ for $M < 1$ and $\alpha = 0.6$ for $1 < M < 10$

The dimensionless breakthrough time is computed by Bournazel [12] as:

$$t_{DBT} = \frac{Z}{3-0.72Z} \tag{7}$$

and

$$Z = \frac{4.9177\times10^{-5}\Delta\rho k_h h(h-h_p)}{\mu_o B_o Q_o} \tag{8}$$

4. Well performance after breakthrough

There is always the economic propensity to produce a well above the critical rate. First, a model must be developed to tag a value to the critical rate as a function of well and reservoir properties. So, the choice to produce the well above the estimated critical rate is followed by predicting the water breakthrough time. After the breakthrough time, the well performance is impacted heavily by the amount of water to oil production, generally termed water-cut.

Prediction of water-cut performance usually requires the use of complicated and costly numerical models [13]. The application of numerical simulation to studying coning behavior is one of the most daunting numerical analysis techniques. However, Letkeman [14] designed a two-dimensional radial finite difference model to evaluate coning behavior of gas or water in a single well. The finite-difference equation was formulated into Implicit-Pressure Explicit-Saturation (IMPES) scheme and solved using Alternating Direction Implicit Procedure (ADIP). Using numerical models, Miller [15] investigated the effect of bottom-water on the short-term and long-term performance of wells.

Although these numerical models offer a great deal of flexibility, they require highly detailed input data and consume large amounts of computer time and money. It is against this backdrop that the study combined the works of Kuo [13] and Permadi [16] to develop an empirical correlation procedure to predict the well performance after breakthrough. Compared to the complicated numerical models, the correlation is particularly useful when detailed reservoir data are not available, or when decision time and project cost is limited. Field engineers use the simplified correlation to compare water-cut performance for various operating strategies and make appropriate decisions for production operations [13].

4.1. Vertical Well performance after breakthrough

Kuo [13] developed a generalized correlation of water-cut performance as a function of reservoir and well parameters by normalizing the simulation results. The procedure is summarized thus:

1. Compute water breakthrough time, t_{BT}
2. Select any time after breakthrough such that $t > t_{BT}$
3. Calculate the dimensionless breakthrough time ratio t_{DBT} as:

$$t_{DBT} = t/t_{BT} \tag{9}$$

4. Compute the limiting value for water-cut from:

$$f \frac{Mh_w}{Mh_w+h_{wlim}} \tag{10}$$

The mobility ratio is defined in Equation 6. The current oil zone thickness h and water zone thickness $h_w$are defined in terms of the initial thickness of oil and water zones, $H_o$and H_w respectively as:

$$h = H_o\left[1 - \frac{N_p}{N}\left(\frac{1-S_{wc}}{1-S_{wc}-S_{or}}\right)\right] \tag{11}$$

$$h_w = H_w + H_o\left[\frac{N_p}{N}\left(\frac{1-S_{wc}}{1-S_{wc}-S_{or}}\right)\right] \tag{12}$$

The cumulative oil production is calculated at the breakthrough time using the total production Q as:

$$N_p = Qt_{BT} \tag{13}$$

With limited data constrained to the geology of the reservoir, the volumetric method could prove effective in computing the initial oil in place as:

$$N = \frac{7758Ah\varphi(1-S_{wc})}{B_{oi}} \tag{14}$$

5. Calculate the dimensionless water cut f_{wD} based upon the dimensionless breakthrough time ratio as given by the following relationships:

$$f_{wD} = \begin{cases} 0.0, t_{DBT} < 0.5 \\ 0.94\, log\, t_{DBT} + 0.29, 0.5 \le t_{DBT} \le 5.7 \\ 1.0, t_{DBT} > 5.7 \end{cases} \tag{15}$$

6. Compute the actual water-cut as:

$$f_w = f_{wD} \times f_{wlim} \tag{16}$$

7. Share the total well throughput into the water and oil flow rate using the water-cut as:

$$Q_w = f_w \times Q \tag{17}$$

$$Q_o = (1 - f_w) \times Q \tag{18}$$

8. Using the breakthrough time as a starting point, express the oil flow rate to cumulative production as:

$$N_{pj} = N_{pj-1} + 0.5 \sum_{j=1}^{n} \left(Q_{oj} - Q_{oj-1}\right)\left(t_j - t_{j-1}\right) \tag{19}$$

9. Finally, estimate the recovery factor thus:

$$RF = N_p/N \tag{20}$$

4.2. Horizontal Well performance after breakthrough

Permadi [16] developed a procedure to predict horizontal well water-cut after breakthrough in a thin oil rim reservoir. The study relied on Permadi's procedure because it was derived from the analytical solution to fluid flow equations combined with mass conservation equations. The procedure is not a correlation and as such the possible error introduced is on the basis of assumptions made in solving the fluid flow equations. The cross section of the idealized basis for the development of horizontal well behavior after breakthrough is shown in Figure 1. A horizontal wellbore drains oil from a thin oil rim reservoir with a square drainage area of A. The thickness of the initial oil column is h, the length of the horizontal section is L, and the vertical distance of the wellbore axis from the initial water-oil contact is d.

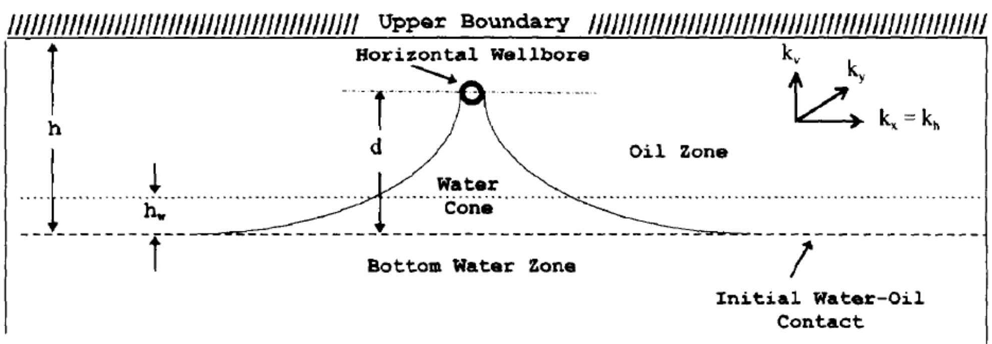

Figure 1. Ideal Basis for Development of Horizontal Well Behavior after Breakthrough [16]

The model assumes that the reservoir is a tank model bounded at the top and lateral sides. A flat water-oil contact is the bottom side that separates the oil zone from an active underlying aquifer. The horizontal well is placed in the middle of the drainage area and is parallel to the plane of water-oil contact. The reservoir fluids flow mode is linear and slightly compressible. In the oil zone, oil flows at initial water saturation. At the same time in water invaded oil zone with an average thickness h_w, the bottom water moves horizontally at residual oil saturation. This water flows vertically toward the wellbore through a narrow water cone. A thin oil zone is assumed and therefore the reservoir pressure at the water oil contact is constant at all times. The effects of wellbore radius on coning behavior, capillary and gravity forces are all assumed to be negligible.

If h_w is the average thickness of water-invaded zone at a given time *t,* and *d* is the vertical distance from the initial water-oil contact to the wellbore, then the distance for the bottom water to reach the wellbore is $d - h_w$. Assuming linear flow into the wellbore, the inflow equation for water becomes:

$$q_w = \frac{1.127\times10^{-3} k k_{rw@S_{or}} L h_w}{\mu_w} \times \frac{\Delta p_w}{d - h_w} \tag{21}$$

The inflow equation for oil is:

$$q_w = \frac{1.127\times10^{-3} k k_{ro@S_{wc}} L(h - h_w)}{\mu_o} \times \frac{\Delta p_o}{h - h_w} \tag{22}$$

At the current water-oil interface, $\Delta p_w = \Delta p_o$ such that the reservoir water cut is defined as:

$$\frac{q_w}{q_o} = \frac{k_{rw@S_{or}} \mu_o}{k_{ro@S_{wc}} \mu_w} \times \frac{h_w}{d - h_w} \tag{23}$$

To account for the influence of the length of the horizontal section, wellbore position, reservoir anisotropy, and the effective drainage area contributing to the flow of oil and water, Permadi [17] modified Equation 23 by introducing the dimensionless flow geometric factor given as:

$$\frac{q_w}{q_o} = 0.025 Q^{0.23} M^{0.45} \left(\frac{X_e Y_e}{dL}\right)^{0.503} \left(\frac{k_v}{k_h}\right)^{0.14} \frac{h_w}{d - h_w} \tag{24}$$

from which the surface water-cut can be computed as:

$$f_w = \frac{1}{(q_o/q_w)(B_w/B_o) + 1} \tag{25}$$

The average thickness of water invaded zone at a given time *t* was calculated assuming constant gross production as:

$$h_w = h_{wBT} + \frac{5.615 Q B_{oi}(t - t_{BT})}{X_e Y_e \varphi (1 - S_{or})} \tag{26}$$

where h_{wBT} is the average thickness of water invaded oil zone at the breakthrough given as:

$$h_{wBT} = \frac{5.615 Q B_{oi} t_{BT}}{X_e Y_e \varphi (1 - S_{or})} \tag{27}$$

Once the water-cut is estimated, steps 7 to 9 of vertical well performance are followed.

5. Results and discussions

Before a thin oil rim reservoir is developed to optimize recovery, the first question is whether to produce the field with vertical or horizontal wells. Such decisions are based on the design parameters estimated from limited geologic data. The design parameters include effective wellbore radius, estimated skin factor, critical rate, breakthrough time and cumulative production before breakthrough. Table 2 shows the simulated output for the design parameters. The effective wellbore radius is 258.34ft in lieu of the actual radius of 0.51. That is, the well appears to have a radius of 507 times the actual radius, indicating a negative skin factor of 6.23.

Table 2. Before breakthrough performance analysis for W1, W2 and W3

Parameters	Well 1		Well 2		Well 3	
	Vertical Well	Horizontal Well	Vertical Well	Horizontal Well	Vertical Well	Horizontal Well
Effective Well Radius [ft]	0.51	258.34	0.51	288.97	0.51	230.42
Estimated Skin	-0.0002	-6.23	-0.0002	-6.34	-0.0002	-6.11
Critical Rate [Stb/day]	13.54	82.97	7.01	33.83	17.92	90
Breakthrough Time [days]	0.01	13.31	0	1.56	0.01	5.71
Cumulative production [Stb]	7.46	9646.6	2.65	1581.49	10.86	5705.59

5.1. Breakthrough performance

The critical rates of the horizontal and vertical wells are 82.97 and 13.54Stb/day respectively for W1. Again, the horizontal well has a higher tendency to be produced at a rate 6 times the vertical well without coning. It will take the horizontal well 13.31 days for coning to occur whereas coning will occur in the vertical well at 0.01 days. If the field were to be produced by a vertical well, water production will be observed at about 15 minutes after the well is put on stream. The effect of this short breakthrough time is felt not only on the negligible cumulative production (7.46Stb) but also on the cost and time spent to design and install water handling equipment. In contrast, the horizontal well will cumulatively produce 9646.6Stb before water breaks through. A similar pattern is observed from wells 2 and 3 in Table 2.

It is expected that the longer the length of horizontal well, the more the production period efficiency. Fig. 2 shows that as the well length increases, the cumulative oil production increases monotonically without any turning point, implying that fully penetrated wells will give optimum oil recovery from thin oil rim reservoirs. However, horizontal wells cannot penetrate all the drainage area due to technical constrains and cost, thus it is suggested that the length of horizontal wells be extended to at least one-third of the drainage length for optimal oil recovery. Wells W2 and W3 were analyzed using the same approach and similar observations and conclusions were drawn. The results are presented in Figures 3 and 4.

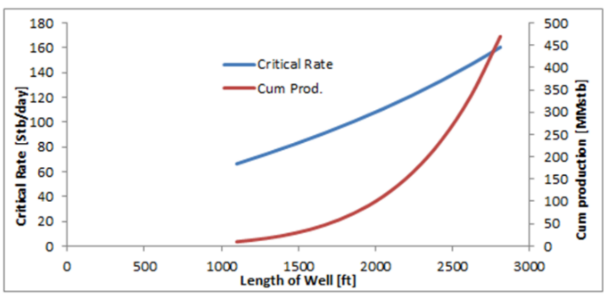

Figure 2. Optimization of Horizontal Well Length for W1

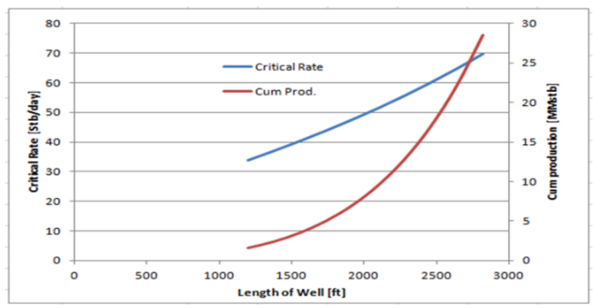

Figure 3. Optimization of Horizontal Well Length for W2

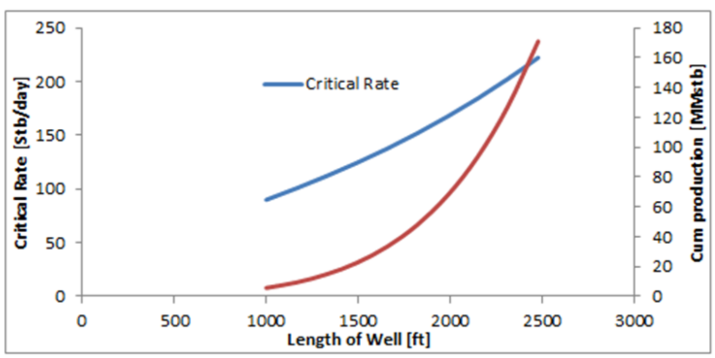

Figure 4. Optimization of Horizontal Well Length for W3

5.2. After breakthrough performance

The after water breakthrough performance of the horizontal wells were evaluated and compared with results of the vertical wells in terms of cumulative oil production and water cut. Generally, the performances of cumulative oil production and water-cut with the horizontal wells are better than the performances of the vertical wells with time. Figure 5 shows that water production from the vertical well is far greater than water production from the horizontal well while cumulative oil production from the horizontal well is far higher than that of the vertical well. In the vertical well, the water cut at the early time spiked as much as 87% and then stabilized. On the contrary, the water cut of the horizontal well steadily rose from about 35% to 50%. The water production scenario of well 2 and 3 is worse because at a very early stage, the water-cut from the vertical wells was about 95% before it stabilized, meaning that draining the reservoir with vertical wells will be very uneconomical. The pattern of cumulative oil production results of W2 and W3 are similar to the results of W1.

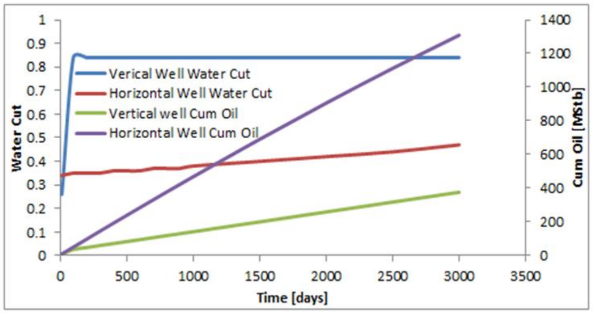

Figure 5. Analysis of After Breakthrough Performance for W1

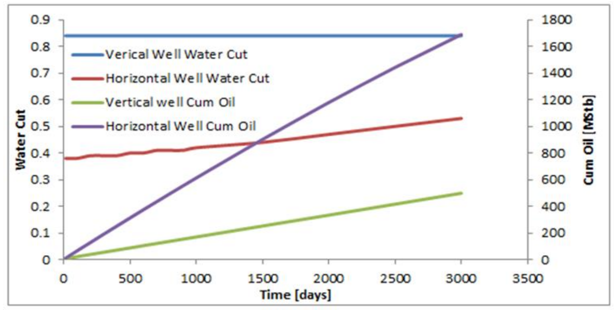

Figure 6. Analysis of After Breakthrough Performance for W2

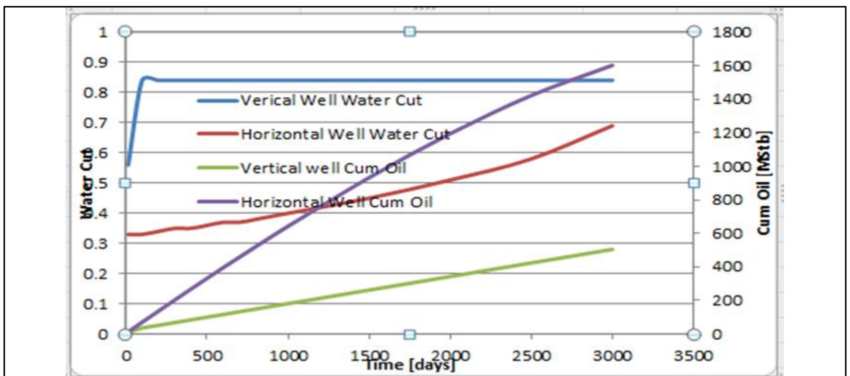

Figure 7. Analysis of After Breakthrough Performance for W3

6. Conclusions

The conclusions drawn from this work are as follows:

1. Oil recovery efficiency from thin oil rim reservoirs is higher with horizontal wells than with vertical wells.
2. Cumulative oil production from thin oil rims using horizontal wells increase as the length of the well increases; meaning that fully penetrating the reservoir will optimally improve oil recovery.
3. The length of horizontal wells used for oil production from thin oil rim reservoirs should be at least one-third of the drainage length for optimal oil recovery.
4. Water cut and water conning from thin oil rim reservoirs using horizontal wells are highly minimized than with vertical wells.

Recommendation

The following are the recommendations made from this study:

1. Horizontal wells can be used to effectively produce oil from thin oil rim reservoirs than vertical wells with reduced coning problem and reduced water-cut.
2. The length of horizontal wells should be at least one-third of the drainage length for optimal oil recovery.

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