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Horizontal Well Performance in Thin Oil Rim Reservoirs

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Abstract

A horizontal well in a thin oil rim was simulated using Eclipse100 to ascertain the effect of different lengths of the horizontal section of the well and oil production rates on oil recovery efficiency. Five different scenarios were simulated and compared with a Base case. The two variables were increased by 50%, 100% and 150% with respect to the base case for cases one, four and five respectively. The horizontal well length and oil production rates for case two were increased by 100% and 50% respectively while those of case three were increased by 50% and 100% respectively. Results show that the first and second cases yield the same cumulative production of 310,000stb (35,000 more than the base case) for the period of one year under consideration. The third and fourth cases had the same cumulative production of 350,000stb while the value of the fifth case was 380,000stb. The Field pressure rates are inversely proportional to the increases made on the horizontal well length and production rate. From this study, it can be deduced that increasing the horizontal well length and the oil production rate will increase cumulative oil production and the efficiency of the recovery.

Keywords: Horizontal Well length, Simulation, Thin Oil Rim, Production Rates, Cumulative Production

Introduction

Producing from a horizontal well is a technology that has to be mastered. Reservoir simulation has been a method adopted to evaluate, estimate and predict the performance of oil production facilities.

Reference [1] focused on the development of a thin, “pancake” type oil column of 13ft - 26 ft thickness which underlies the Snapper N-1gas reservoir. Performance of the oil wells was seen to be very encouraging, but also variable with a wide range of producing GORs, water cuts and wellhead pressures.

Reference [2] highlighted two advantages of oil production from horizontal wells which are increase in productivity of each well and new approach to solving reservoir-engineering problems resulting from heterogeneities. The aim of this paper is to propose elements of analysis focusing on flow line patterns and pressure distribution in an oil field. These elements should be of help to decision-makers when faced with the economic choice between spudding vertical or horizontal wells and eventually fracturing them.

Production with horizontal wells offers a new approach to reducing water coning effects. [3]. He evaluated the effect water cresting would have under a horizontal well and determine the critical flow rate by fully analytic 2-D methods, developed in vertical planes perpendicular to the axis of the Horizontal well. He concluded that the best position for a horizontal well with respect to its production rate for the gas-cap drive model with a non-active aquifer should carefully be determined. [4, 11,17].

The equation for calculating the pseudo steady-state of horizontal wells derived from the known productivity equation of vertical wells was presented by [4]. Application of this equation requires the determination of two parameters, the geometric factor that accounts for effect of the permeability anisotropy and the skin factor as a result of restricted entry which accounts for the well length. They concluded that many variables affect the productivity of horizontal wells but the well length and degree of penetration have the greatest effects, this has been confirmed by 12 and18 [12,18].

After a pilot horizontal well was completed in the Erb West field off-shore East Malaysia, five horizontal wells were drilled during 1990. Three additional horizontal wells were be drilled in 1991. The objective of the wells was to develop a 40 m thick oil rim, maximizing the oil recovery and offtake rates, while delaying gas and water breakthrough. Drilling short pilot holes at the entrance of the horizontal section to establish accurately the depth of the fluid contacts is important to achieve optimum placement of the horizontal hole with respect to the contacts. The main advantages of horizontal wells in an oil rim environment are improved productivity, higher recovery and higher critical rates for water and gas coning.[5].

Reference [6, 19] initiated studies to determine the best development scheme to recover oil and gas from two oil rim reservoirs off shore Abu Dhabi utilizing horizontal wells. One pilot horizontal well has already been drilled in the lower reservoir and few more are planned. Due to uncertainties in the fluid contacts and reservoir characteristics, a vertical pilot hole had to be drilled and cored to decide on the optimum location of the horizontal hole.

Effective exploitation of the thin oil rim was particularly challenging because of the size of the overlaying gas cap and the thickness of the oil rim varying between 31 to 46 feet gross pay interval. Since oil wells in the thin oil rim of the sand did not justify well cost, the challenge, then, was to make the oil wells more attractive to facilitate early depletion of the oil rim. Reservoir simulation work was undertaken and a joint team was formed to evaluate the reservoir performance and determine the best strategy for depletion. The performance of the two wells in the reservoir was history-matched and then the model was used to develop an improved strategy. Sensitivity analysis was conducted to demonstrate that locating longer horizontal oil wells with larger size tubing in the upper third of the oil rim proved to be the best strategy for depletion of the oil rim. [7].

Coning or cresting of unwanted fluids into the wellbore in both vertical and horizontal wells is the main challenge when trying to maximize oil recovery in thin and ultra-thin (<30ft) oil columns. A reasonable volume of oil left behind, above the well completion, in the reservoir may also occur in horizontal wells when bottom or edge water encroachment takes place. [8]. They proposed a smart development strategy for the development of these challenging reservoirs. Smart development strategy involves intelligent multilateral wells for simultaneous oil and gas production. The top horizontal wells of the multilateral well was completed at the crest of the reservoir in the gas cap while the lower horizontal well was completed, right above the gas-oil contact. Extensive numerical simulation was used to show that the intelligent multilateral wells significantly improve the overall cumulative production of gas and oil from a thin oil reservoir with large gas cap compared to conventional wells and also provide opportunity for auto gas lift for low API gravity crude.

Reference [9] stated that thin oil rims associated with gas-condensate field development have one common problem which is low oil recovery. The main reasons are fast gas and water coning of the producers result in sharp oil rate decline and low cumulative oil production per well. Analysis of several scenarios of oil rim development with different well completion and gas cap development at different timing are given. Several factors were estimated with strong impact on the effectiveness of oil rim development (oil rates decline, water cut and gas-oil ratio growth, cumulative oil production per well): capillary pressure definition, well completion (horizontal vs. deviated), gas production from cap. Several conclusions were reached: cumulative oil production from thin rims is very sensitive to the capillary pressure value, horizontal completion is most effective for rim development; limited production from the gas cap simultaneously with oil production could lead to a higher oil recovery at certain geological conditions.

This project was conceived to evaluate the effect of changes in horizontal well length and oil production rate on a well in a thin oil column that is susceptible to coning. When recovering fluid from a reservoir, it is important to maximize the recovery and minimize coning tendencies. The well must be produced in such a way as to reduce the damage to the wellbore and ensure a cost effective recovery. In the base case of this study, the well was produced at a rate of 2000 stb/d and the horizontal length section of the well was 1000 ft. A simple box model of dimension 20*9*9 was used to represent the reservoir. ECLIPSE 100 was used to simulate various conditions of a horizontal well under the following conditions:

- Initial bubble point pressure is equal to the grid block oil pressure in each grid block.
- Well is drilled to produce from the middle of the layer and varying the horizontal well lengths.

Statement of the Problem

The problem deals with oil recovery from a thin oil column which is prone to coning as a result of the underlying aquifer. The relative permeabilities and the Black-oil fluid properties of the Second SPE Comparative Solution Project were used but the reservoir and capillary pressure data are different. Figure 1 shows the grid system that is used for the study and the thicknesses in the z direction are shown in Table 1. Fluids are produced from a horizontal well drilled through the grid block centers and the whole of the horizontal section is open to flow.

Methodology

ECLIPSE 100 was used in this study to evaluate the effect of horizontal well length increase and production rate increase on the cumulative oil production and recovery efficiency.[10]. Five scenarios were simulated by increasing the horizontal well length and oil production rate by different proportions relative to the base case. Table 1 and 2 show the reservoir data and fluid property data respectively for the system. Table 3 shows the different scenarios that were simulated.

Transient Well Testing for Horizontal Well

Transient pressure analysis of horizontal wells is more complex than that of vertical wells because most horizontal well models assume that horizontal wells are perfectly horizontal and are parallel to the top and bottom boundaries of the reservoir. However, in reality the horizontal wellbores are rarely horizontal, because of many variations in the vertical plane along the well length which affects pressure gauge inserted at the producing end of a horizontal well. Calculation of horizontal wells transient testing is not straightforward because it exhibits negative skin factors and it is difficult to estimate the exact production length of a long horizontal well, even though the whole horizontal section of the well is known.

Flow Equations for Horizontal Oil Wells

This section describes steady-state fluid flow through a reservoir. Mathematical equations are included for horizontal oil wells. In oil wells, normally pressure instead of pressure squared and pseudo-pressure methods are used to describe the relationship between pressures and flow rates. Steady-state flow rate can be predicted by using several solutions which are available in the literature. [13,14, 15,16].

These solutions in US Oilfield Units are given as follows.

Joshi's[19] Method

$$Q_h = \frac{0.007078 k_h h\left(\bar{p}_R - p_{wf}\right)/\left(\mu_o \beta_o\right)}{\ln\left[\dfrac{a+\sqrt{a^2-(L/2)^2}}{L/2}\right] + (h/L)\ln\left(h/2r_w\right)} \quad (1a)$$

where

$$a = (L/2)\left[0.5+\sqrt{0.25+\left(2r_{eh}/L\right)^4}\right]^{0.5} \quad (1b)$$

Borisov's[13] Method

$$Q_h = \frac{0.007078 k_h h\left(\bar{p}_R - p_{wf}\right)/\left(\mu_o \beta_o\right)}{\ln\left[(4r_e/L)+(h/L)\ln\left((h/2\pi r_w)\right)\right]} \quad (2)$$

Giger et al's[20] Method

$$Q_h = \frac{0.007078 k_h L\left(\bar{p}_R - p_{wf}\right)/\left(\mu_o \beta_o\right)}{(L/h)\ln\left[\dfrac{1+\sqrt{1-\left(L/2r_{eh}\right)^2}}{L/(2r_{eh})}\right] + \ln\left[(h/2\pi r_w)\right]} \quad (3)$$

Giger et al's[20] Method

$$J_h/J_v = \frac{\ln\left(r_{ev}/r_w\right)}{\ln\left[\dfrac{1+\sqrt{1-\left(L/2r_{eh}\right)^2}}{L/(2r_{eh})}\right] + (h/L)\ln\left[(h/2\pi r_w)\right]} \quad (4)$$

Renard and Dupuy's[15] Method

$$Q_h = \frac{2\pi k_h\left(\bar{p}_R - p_{wf}\right)}{\left(\mu_o \beta_o\right)}\left[\frac{1}{Cos^{-1}(x) + (h/L)\ln\left[(h/2\pi r_w)\right]}\right] \quad (5)$$

Where

x = 2a/L for ellipsoidal drainage area

a = half the major axis of drainage ellipse

Giger et al's[20] Method

$$Q_h = \frac{2\pi k_h L\left(\bar{p}_R - p_{wf}\right)}{\left(\mu_o \beta_o\right)} * \left[\frac{1}{(L/h)\ln\left[1+\sqrt{1-\left(L/2\pi r_{eh}\right)^2}\right]}\right] + \ln\left[h/2\pi r_w\right] \quad (6)$$

In Equations 1 through 6

L = horizontal well length, ft

h = reservoir height, ft

r_w = wellbore radius, ft

r_{ev} = drainage radius of vertical well, ft = $\sqrt{(acres * 43560)/\pi}$

r_{eh} = drainage radius of horizontal well, ft = $\sqrt{(2 * acres * 43560)/\pi}$

μ_o = oil viscosity, cP

β_o= Oil formation volume factor, rb/stb

Δp = (P_R —P_{wf}) = pressure drop from drainage boundary to the wellbore, psi

Q_h = horizontal well flow rate, stb/day

J_h = $Q_h/\Delta p$= productivity index for horizontal oil well, stb/(day/psi)

J_v = $Q_v/\Delta p$ = productivity index for unstimulated vertical index, stb/(day/psi)

$$J_h = \frac{0.007078 k_h h / (\mu_o \beta_o)}{\ln [r_{ev} / r_w]} \quad (7a)$$

$$J_{v(simulated)} = \frac{0.007078 k_h h / (\mu_o \beta_o)}{\ln [r_{ev} / r_w + s]}$$

$$= \frac{0.007078 k_h h / (\mu_o \beta_o)}{\ln [r_{ev} / r'_w]} \quad (7b)$$

Where

$$r'_w = r_w \exp(-s) \quad (7c)$$

$$s = -\ln\left(\frac{r'_w}{r_w}\right) \quad (7d)$$

For damaged well, $s > 0$ and for stimulated well, $s < 0$.

Results and Discussion

In Fig. 2, the field oil production rate is seen to vary inversely with respect to increases in horizontal well length and oil production rate. The first case is a 50% increase in both the horizontal well length and the production rate with respect to the base case. Second case is 100% and 50% increase in the horizontal well length and oil production rate respectively. These two cases produced the same results in the simulation. Cases 3 and 4 also yielded the same result throughout the simulation. From Figure 2, the field oil production rate starts from 1400stb/d and reduces to 482stb/d at the end of the year while cases 1 and 2 starts from 2300stb/d and end at 522stb/d at the end of the year. Cases 3 and 4 starts from 2780stb/d and depletes to 544stb/d at the end of the year. The fifth case started from 3460stb/d and ends at 575stb/d by the end of the period.

The water cut is directly proportional to increases in the horizontal well length and increase in oil production rates (Figure 3). The water cut increases in all the five cases, however, the result in cases 1 and 2 are the same with a climax at (0.04) while that of cases 3 and 4 climaxed at (0.065) at the end of the one year of simulation. The maximum value of the base case and case 5 were 0.025 and 0.085 respectively at the end of the simulation. Figure 4 shows the effect of horizontal well length and oil production rate on the field gas-oil ratio for the period under consideration. The field gas-oil ratio is directly proportional to the increase in the horizontal well length and oil production rate increases. The maximum value of FGOR for the base case is 3.6 Mscf/stb, while the maximum values of cases 1 and 2 and that of cases 3 and 4 are 5.1 Mscf/stb and 6.5 Mscf/stb respectively for the one year period. The maximum value for case 5 is 7.75 Mscf/stb. Figure 5 shows the cumulative production of the system. Case 5 had the highest value of 380,000stb while case 1 had the lowest value of 275,000stb. The cumulative production of cases 1 and 2 was 310,000stb and cases 3 and 4 were 350,000stb for the period. The pressure profile for the reservoir is shown in Fig. 6. The initial pressure of the system was 3990 psia which experienced a pressure drop of 210 psia as it reduced to 3780psia for the base case. Case 1 and 2 reduced to 3675psia, cases 3 and 4 reduced to 3580psia and case 5 reduced to 3500psia for the period of the simulation.

Conclusions

This study deals with the effect of varying the production rate and the horizontal well length in a reservoir with a thin oil column that is susceptible to coning.

The simulation of the horizontal well showed that increase in horizontal well length and production rate is desirable because it enhances ultimate recovery from the wellbore.

An optimum well length as well as production rate should be chosen to maximize cumulative production.

Horizontal wells increase the contact area and drainage area in a given time period and in high permeability oil reservoirs reduce near-wellbore turbulence and enhance well deliverability. Horizontal wells are known to have high potentials in oil reservoirs.

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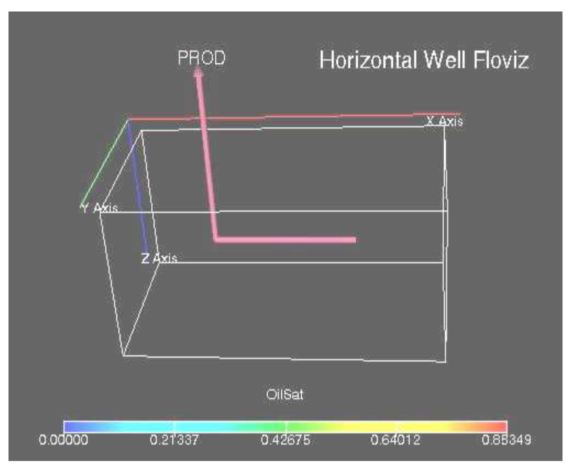

Fig. 1. Horizontal well in a thin Oil Rim

Table 1. Reservoir Data and Initial Description

Layer	Thickness Δz (ft)	Depth to centre of Layer	Horizontal Permeability (md)	Vertical Permeability (md)	P_{oil} (Psia)	S_o	S_w
1(top)	20	3600	300	30	3600	0.711	0.289
2	20	3620	300	30	3608	0.652	0.348
3	20	3640	300	30	3616	0.527	0.473
4	20	3660	300	30	3623	0.351	0.649
5	30	3685	300	30	3633	0.131	0.869
6(bottom)	50	3725	300	30	3650	0.000	1.000

Table Fluid Property Data

Pressure, (psia)	Solution GOR, Rs (SCF/STB)	OIL FVF, B_O (RB/STB)	GAS FVF, B_g (RB/SCF)	Oil Viscosity, μ_o (cp)	Gas Viscosity, μ_g (cp)
400	165	1.0120	0.00590	1.17	0.0130
800	335	1.0255	0.00295	1.14	0.0135
1200	500	1.0380	0.00196	1.11	0.0140
1600	665	1.0510	0.00147	1.08	0.0145
2000	828	1.0630	0.00118	1.06	0.0150
2400	985	1.0750	0.00098	1.03	0.0155
2800	1130	1.0870	0.00084	1.00	0.0160
3200	1270	1.0985	0.00074	0.98	0.0165
3600	1390	1.1100	0.00065	0.95	0.0170
4000	1500	1.1200	0.00059	0.94	0.0175
4400	1600	1.1300	0.00054	0.92	0.0180
4800	1676	1.1400	0.00049	0.91	0.0185
5200	1750	1.1480	0.00045	0.90	0.0190
5600	1810	1.1550	0.00042	0.89	0.0195

Other Reservoir and Fluid Properties

Oil Compressibility for undersaturated oil ($Psia^{-1}$)	10^{-5}
Oil viscosity compressibility for undersaturated oil ($Psia^{-1}$)	0.0
Stock tank oil density, ρ_{osc}(Ibm/ft^3)	45.0
Standard condition gas density, ρ_{gsc}(Ibm/ft^3)	0.0702
Water compressibility, C_w ($Psia^{-1}$)	$3*10^{-6}$
Water compressibility, C_r ($Psia^{-1}$)	$4*10^{-6}$
Porosity , fraction	0.2
Water formation volume factor at reservoir temperature and atm. Pressure, B_w(rb/stb)	1.0142
Water density at standard condition ρ_w(Ibm/ft^3)	62.14
Reference pressure for water FVF and densities P_w (psia)	14.7
Water viscosity μ_w (cp)	0.96

Table 3. Varying well lengths and rates used in this study

Scenarios	Horizontal We Length, (ft)	Field Oil Production Rate, (STB/D)
(Base case)	*1000*	*2000*
1	*1500*	*3000*
2	*2000*	*3000*
3	*1500*	*4000*
4	*2000*	*4000*
5	*2500*	*4500*

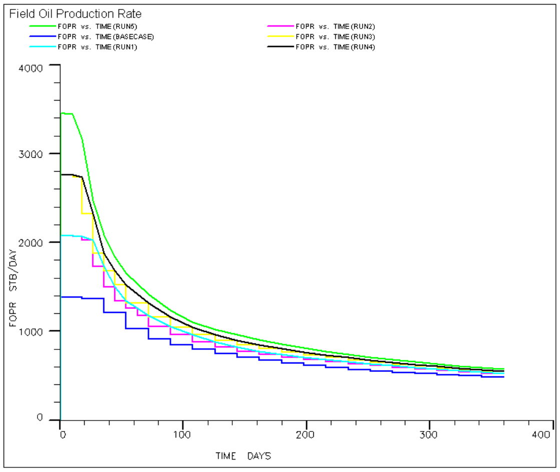

Fig. 2: Field Oil Production Rate.

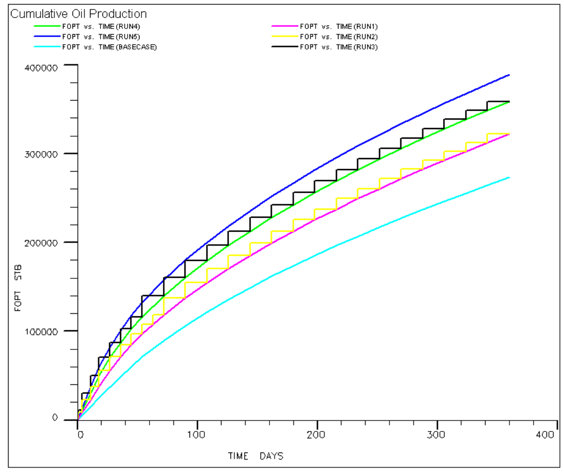

Fig. 5: Cumulative Oil Production

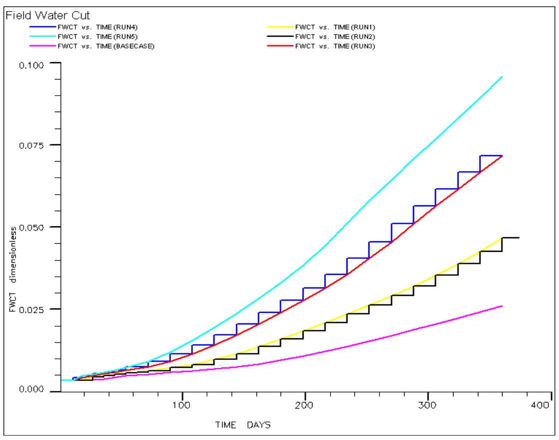

Fig. 3: Field Water Cut

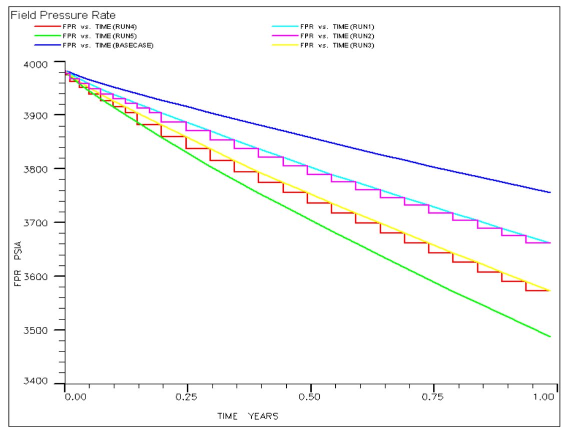

Fig. 6: Field Pressure Rate

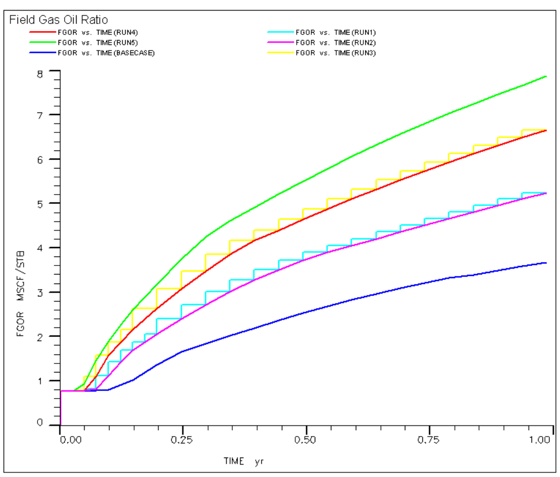

Fig. 4: Field Gas-Oil Ratio