ISSN 2229-5518

Optimization of Waterflooding Patterns in Multilateral Wells – a Numerical Simulation Approach

M.B. Adamu[1], A.D.I. Sulaiman[1], A.A. Shamsudeen[1] and A.I. Auwalu[1]

Abstract— Multilateral wells have been documented to afford better production performance than vertical wells in primary oil recovery processes especially in thin reservoirs. However, little is known about how multilaterals perform relative to vertical wells in water-injection secondary recovery processes, and how the configuration and pattern of arrangement of these multilaterals affect their performance. In this work, Boast98, a three-dimensional, three-phase, black oil reservoir simulator was used to simulate different waterflooding schemes involving various multilateral well configurations and patterns of arrangement using a synthetic reservoir of a given areal extend in order to compare the performance of vertical wells against multilaterals in a water-injection secondary oil recovery operation. Basically four types of multilateral well configurations were investigated which included the Dual lateral (two laterals), the Trilateral (three laterals), the Quadlateral (four laterals), and the Multilevel (four laterals) well configurations. Vertical and horizontal wells were used as base cases against which the performance of multilaterals were judged. The vertical five-spot pattern performed better than the best multilateral well scenario in terms of cumulative oil produced. All multilateral wells considered were found to be more profitable than vertical and horizontal wells because of their accelerated rate of recovery and reduced water production. The only exception was the trilateral six-spot pattern.

Index Terms— Secondary oil Recovery, Water injection, multilateral completion, numerical simulation, water flooding, well patterns, production performance.

---

1 Introduction

In the pursuit of optimal production, cost reduction and maximum reserve recovery, operating companies in the petroleum industry are placing increasing emphasis on multilateral completions. More than 15% of new wells drilled each year are candidates for this type of completions (Palsson et al., 2003).

During the last two decades, the oil industry has experienced an upsurge in the number of horizontal and multilateral wells being drilled. The use of horizontal and multilateral wells instead of vertical ones improves the performance of waterflooding projects in terms of productivity, reduce gas and/water coning problems, and increase the sweep efficiency (Algharaib and Gharbi, 2005).

Although many studies have focused on the use of horizontal and multilateral wells in exploiting a reservoir, there are limited studies dealing with the use of these wells in water injection projects. Ozkan and Raghaven, (1990) developed an approximate analytical method to predict the breakthrough time for both horizontal and vertical wells. Gharbi et al., (1996) investigated the performance of immiscible displacement with horizontal and vertical wells in heterogeneous reservoirs. They studied the sensitivity of the displacement performance to the horizontal well length and the ratio of the horizontal to vertical permeability using various well combinations. They showed that the degree and structure of the heterogeneity of the reservoir have a significant effect on the efficiency of immiscible displacement with horizontal wells.

Shirif and Tarhumi (2003) showed that horizontal wells can be used to waterflood stratified reservoir with bottom water underlying the oil zone. They developed a new analytical model to predict the performance in this type of reservoir. Algharaib and Garbi (2005) analyzed the overall efficiency of a waterflooding process well pattern using horizontal/multilateral injectors and producers in different configurations. Two configurations were considered: a staggered parallel horizontal well configuration, and an L shaped configuration. The authors showed that main parameters such as breakthrough time, sweep efficiency, injection-production pressure drop, etc are strongly affected by the type of configuration considered. In another work Shirif and Tarhumi (2002) showed a study directed towards reducing water mobility in the bottom water zone to obtain more efficient oil displacement. They examined the effect of vertical and horizontal injection and production well combinations and found that the use of horizontal wells showed slightly better oil recovery over vertical wells in a waterflood of reservoirs under bottom water conditions.

Despite all these works, the effect of design parameters using multilateral wells is yet to be fully investigated. Analytical approaches to waterflood performance prediction, such as the Buckley-Leverett equation, are actually reservoir simulation methods, albeit simple ones. In the mid to late 1950s, alternative approaches started to appear in the technical literature as seen in the works of Torrey P.D., (1950). These were refined and exploited by Sharif et al., (2003); Palsson et al., (2003a); Palsson et al., (2003) and Evans R., (2001) leading to modern numerical reservoir simulation methods (IPIMS).

Numerical simulation treats a reservoir as a collection of contiguous cells or blocks. Perhaps it's best to visualize a cartesian coordinate system, in which case these cells or blocks

---

[1] Department of Petroleum Engineering, Faculty of Engineering and Engineering Technology, Abubakar Tafawa Balewa University, P.M.B., 0248, Bauchi, Nigeria

ISSN 2229-5518

take the form of rectangular parallelepipeds. If all the sides are equal, then they are cubes. Virtually any coordinate system can be employed; however, most reservoir simulators provide two — e.g., the cartesian and the cylindrical systems. For each of these, a continuity equation is developed for each flowing phase or hydrocarbon component, while allowing for the possibility that flow can be either in one, two, or three spatial dimensions (IPIMS).

Water injection is an essential part of many modern oilfield development plans. The high costs and often tight economic margins especially in offshore developments require that the chosen waterflood design not only provides an optimum sweep efficiency and reservoir pressure support to maximize the oil production revenue, but also carries an acceptable level of risk in terms of the project costs and technical uncertainties. While enhanced oil recovery has benefited from multilateral well technology in the area of steam assisted gravity drainage (IPIMS), there seems to be reluctance in embracing this technology for the optimization of secondary processes like water injection despite apparent advantages.

The overall aim of this study is to (a) investigate the effect of multilateral well configurations on water injection performance and (b) to compare the performance of vertical wells against multilaterals in a water-injection secondary oil recovery operation.

2 METHODOLOGY

A three dimensional synthetic reservoir model was used to simulate different waterflood schemes using a three-phase, three-dimensional black oil numerical reservoir simulator-BOAST98. Each of the waterflood schemes was simulated based on the steps illustrated in figure 1.

BOAST98 is a finite-difference implicit pressure/explicit saturation (IMPES) numerical reservoir simulator. It contains both direct and iterative solution techniques for solving systems of algebraic equations. The well model in BOAST98 allows specification of rate or pressure constraints on well performance. It also allows specification of any combination of horizontal, slanted, and vertical wells in the reservoir. Multiple rock and PVT regions may be defined, and three aquifer models are available as options (Ray, 1998). BOAST98 contains flexible initialization capabilities a bubble point tracking scheme, an automatic time step control method, and a material balance check on solution stability (Fanchi, 1982).

2.1 Model Description

The reservoir model is assumed to contain initially only oil and water i.e., zero initial gas saturation. It is homogeneous with respect to porosity, anisotropic with respect to permeability and isothermal with respect to temperature. The physical properties of the reservoir model are summarized in Table 1.

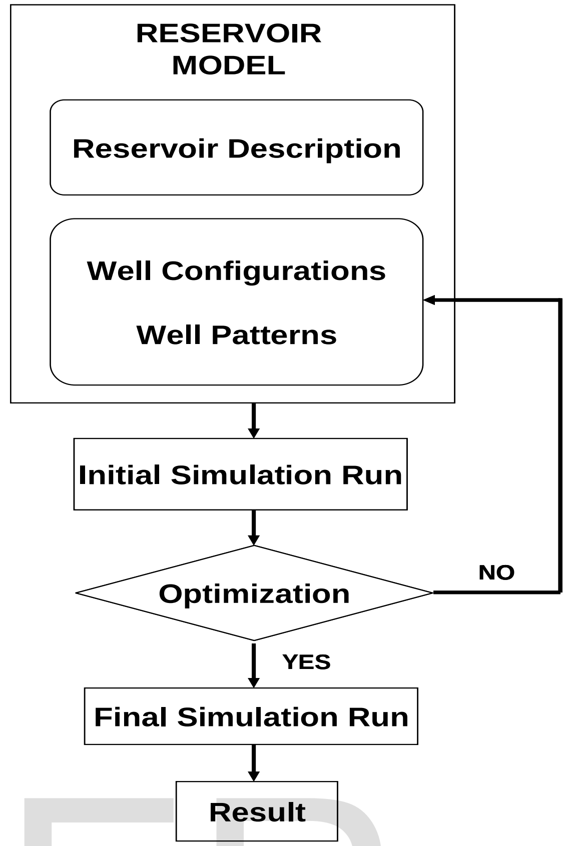


Figure 1: Flowchart for simulating waterflood schemes

2.2 Well Data

Four different types of multilateral well configurations were used. These include: Slanted Dual Lateral - two opposing laterals 180° apart and slanted at 2.9° to the horizontal plane, Trilateral-three laterals 120° apart, Quadlateral-four laterals 90° apart and Multilevel-four laterals in two tiers of two opposing laterals 180° apart. Quadlaterals and trilaterals with slanted laterals were also considered.

Five-spot well patterns and its variations were used for the quadlateral and vertical well configurations, six-spot for the trilateral well configurations and line-drive for the horizontal, dual lateral and the multilevel well configurations. All horizontal and multilateral wells were assumed to have a constant wellbore radius of 4.5", and 7" for all vertical wells. Skin factor for all wells is zero (S = 0). A constant injection pressure of 3000psia (for injection wells) and constant production well flowing bottomhole pressure of 2200psia (above bubble point pressure) were assumed for all well configurations. The properties of the well configurations used are summarized in Table 2 (appendix 1).

The vertical wells were completed throughout the entire formation thickness of (60ft) and their flow indices were calculated to be approximately 0.1. Layer Flow indices were calculated according to:

ISSN 2229-5518

$$PID_{VK} = \left(\frac{0.00708Kh}{\ln\left(\frac{r_e}{r_w} \right) + S} \right) \text{-------------------------(1)}$$

where,
r_e = equivalent gridblock radius, ft
r_w = wellbore radius, ft
h = Z-dimension (layer thickness) of the block, ft
k = mean X-Y permeability in md
S = layer skin factor

Table 1: Reservoir rock and fluid properties

Initial reservoir pressure, psia	2200
Bubble point pressure, psia	2014.6995
Depth to top of reservoir, ft	4325
Rock compressibility, 1/psi	3×10^{-6}
Porosity	0.2
Reservoir Temperature, °F	200
Gas specific gravity	0.792
Constant water viscosity, cp	0.31
Density of oil at stock tank conditions, lbm/cu. ft.	46.244
Density of oil at stock tank conditions, lbm/cu. Ft	62.238
Density of gas at standard conditions (14.7psia), lbm/cu.ft.	0.0647
Capillary pressure, psi	0
N_y	25
N_x	25
N_z	10
K_x, md	10
K_y, md	10
K_x/K_z	10
Δξ, φτ	100
Δψ, φτ	100
Δζ, φτ	6
Reservoir thickness, ft	60
Irreducible water saturation (S_{wc})	0.12
Initial oil saturation (S_{oi})	0.88
Initial gas saturation (S_{gi})	0
Initial water saturation (S_{wi})	0.12
Initial Oil In place (IOIP), MSTB	7837

The radius r_e was calculated from Peaceman's formula:

$$r_e = 0.28 \frac{\left[\left(\frac{k_y}{k_x} \right)^{\left(\frac{1}{2}\right)} dx^2 + \left(\frac{k_x}{k_y} \right)^{\left(\frac{1}{2}\right)} dy^2 \right]^{\left(\frac{1}{2}\right)}}{\left(\left(\frac{k_y}{k_x} \right)^{\left(\frac{1}{4}\right)} \right) + \left(\frac{k_x}{k_y} \right)^{\left(\frac{1}{4}\right)}}$$

-------------------------(2)

K_x = permeability in x-direction
K_y = permeability in y-direction
dx = X-direction gridblock dimension, ft
dy = Y-direction gridblock dimension, ft

The PID calculated above was for a vertical wellbore. PID for a horizontal wellbore was calculated according to the following equations:

$$PID_{HK} = \frac{0.00708K_H h}{\left[\ln\left(\frac{a + \sqrt{a^2 - (L/2)^2}}{(L/2)} \right) + \left(\frac{I_{ani} h}{L} \times \ln \frac{I_{ani} h}{r_w (I_{ani} + 1)} \right) + S \right]}$$

-------------------------(3)

$$\sqrt{k_H / k_v} = I_{ahi}$$

-------------------------(4)

$$a = \left(\frac{L}{2} \right) \times \sqrt{0.5 + \left[0.25 + \left(\frac{r_{eH}}{(L/2)} \right)^4 \right]^{0.5}}$$

-------------------------(5)

Where,
k_H= horizontal permeability (md)
h = Z-dimension (layer thickness) of the block, ft
L = length of well's horizontal section (ft)
k_v = vertical permeability (md)
r_{eH} = drainage radius of the horizontal wellbore (ft)
I_{ani} = the index of horizontal-to-vertical permeability anisotropy
a = the large half-axis (a) of the drainage ellipse formed by a horizontal wellbore

To ensure a realistic representation of the multilateral well configurations and to have good control of the model being waterflooded, the model was thought of as being carved out of a larger reservoir. This implied that all well blocks at the model boundary were being shared by other adjacent well patterns in the larger reservoir. The patterns studied would represent one element of a large number of such patterns in a water injection secondary project. Thus only a fraction of the

ISSN 2229-5518

productivity or injectivity of a boundary well block could be utilized by a well pattern.

2.3 Simulation Runs

With a maximum water-oil ratio (WOR) of 20.00 specified for all producing wells, the reservoir model described above was used to simulate the following waterflood schemes (see Table 2; appendix 1).

2.4 Model Optimization

The optimization criteria used were arrival time of the leading waterfronts at the producing wells (grid blocks) and injection rate. Sensitivity runs were made to determine the best perforation intervals along the laterals necessary to ensure that all leading waterfronts reach the the producing laterals (segments) at approximately the same time while also injecting water at the maximum injection rate possible. When these criteria were not satisfied, (indicated by non-uniform arrival of the leading waterfronts at the producing laterals) the injection rate and injection points were adjusted and the simulation ran again. When the criteria were satisfied the results of the run were recorded and they formed the basic data used for the analysis of the production and economic performances.

3 Results and Discussions

Table 3 (appendix 2) shows the results of the simulation runs. The simulation result was used to conduct a production performance analysis. The criteria used for comparing the production performance of the different well configurations and patterns were their cumulative oil productions. Groups of wells with the same number of laterals, for example, quadlaterals (four laterals) and trilaterals (three laterals) were compared and the best from each group was compared with the best from other groups as shown in figure 2.

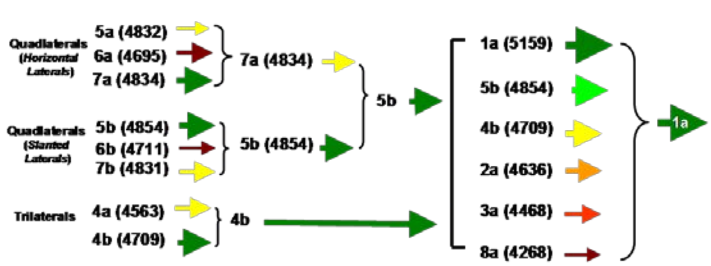


Figure 2: Production performance analysis flowchart

Figure 3 shows how quadlateral (four laterals) well patterns, whose laterals were horizontal wellbores, affected oil recovery. Scenario 7a proved to be more productive than scenarios 6a and 5a. This was because of its superior areal sweep efficiency. Though the difference between the best and the worst performing patterns was small (7a had 3.4% of oil production over 6a), it nevertheless showed the importance of proper pattern selection when using quadlateral wells for waterflooding especially when the oil in place is large.

Slanting the laterals of the quadlaterals affected oil production, though to a small extend (Figure 4). For scenarios 5b and 6b, oil recoveries were increased by about 0.5% and 0.4% respectively. In both cases, the recoveries occurred at longer times compared to their corresponding scenarios with horizontal laterals (5a and 6a). This was because slanting the laterals reduced the contribution of the reservoirs vertical permeability to the laterals' productivity and injectivity. The small increase in production was due to the greater exposure of the laterals to the entire thickness of the reservoir (from the top to the base). This effect was not pronounced because the reservoir was relatively thin (60ft). Slanting the laterals had a different effect on scenario 7a as oil recovery was reduced by about 0.06%. This was a case where the negative effect of reduced injectivity and productivity by slanting overshadowed the positive effect of increased reservoir thickness coverage. The difference between the best performing slanted quadlateral well patterns, 5b, and the worst performing, 6b, was 3.04% signifying that well pattern affected oil recovery more when quadlateral well laterals were horizontal than when they were slanted.

This was a case where the negative effect of reduced injectivity and productivity by slanting overshadowed the positive effect of increased reservoir thickness coverage. The difference between the best performing slanted quadlateral well patterns, 5b, and the worst performing, 6b, was 3.04% signifying that well pattern affected oil recovery more when

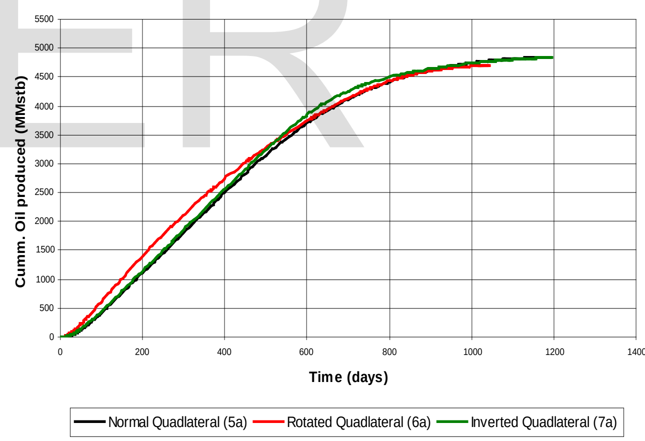
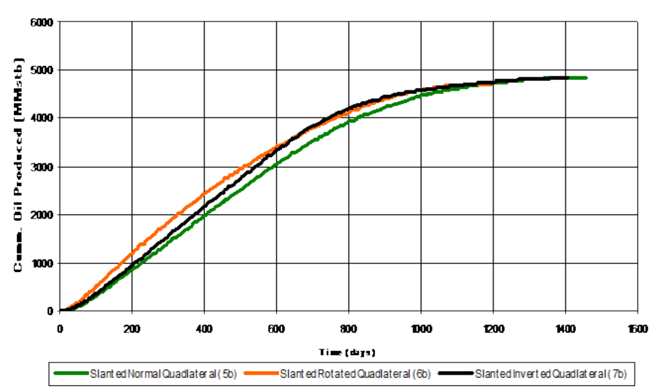


Figure 3: Production performance of quadlateral well pattern options (horizontal laterals)



ISSN 2229-5518

Figure 4: Production performance of quadlateral well pattern options (slanted laterals)

quadlateral well laterals were horizontal than when they were slanted.

From figures 3 and 4, and judging from the oil recovered, the best quadlateral well arrangement (whether slanted or horizontal laterals) was scenario 5b – Slanted Normal Quadlateral (Figure 5). It was this pattern that was used in comparing the quadlateral well configuration with other multilateral well configurations i.e.., dual lateral, trilateral and multilevel wells.

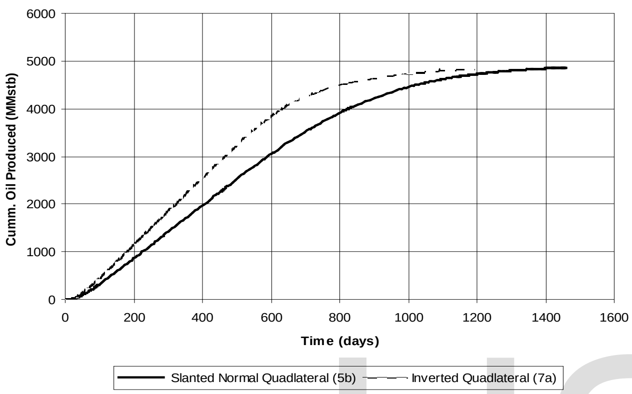


Figure 5: Production performance of quadlateral well pattern options (slanted and horizontal laterals)

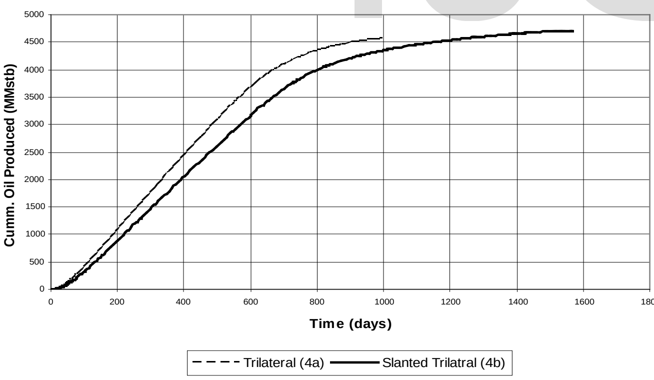


Figure 6: Production performance of trilateral well options (slanted and horizontal laterals).

Just as in the case of quadlateral wells, slanting of the trilateral well laterals led to changes in the amount of oil recovered (Figure 6). Slanting the laterals of scenario 4a increased oil recovery by 3.2%. This indicated that the reduction in productivity and injectivity as a result of slanting was more than offset by the greater exposure of the reservoir thickness to the well laterals which increased displacement efficiency. This however, elongated the time to ultimate recovery by 56%.

The vertical five-spot pattern, scenario 1a, outperformed all well configurations considered in terms of oil recovery because of its high sweep and displacement efficiencies (Figure 7). Oil recovery was increased by 11.3% over the horizontal line drive (2a), 15.5% over the slanted dual lateral line drive (3a), and 9.6% over the best trilateral six-spot (4b), 6.3% over the best quadlateral five-spot (5b), and 20% over the multilevel line drive (8a) patterns and configurations (Figure 8).

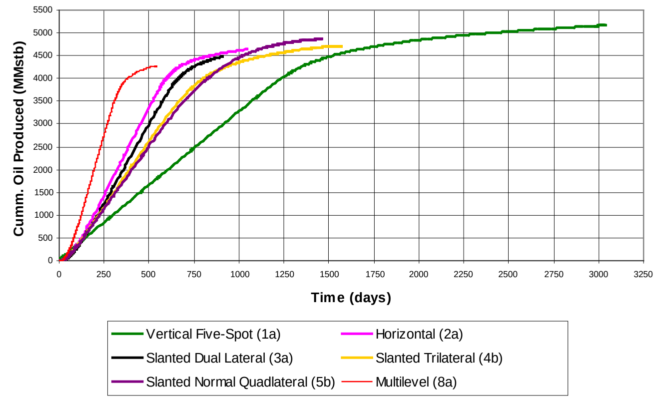


Figure 7: Production performance of well configurations

It is however noteworthy that four vertical production wells were used for the drainage area considered (to ensure a realistic well spacing for this comparison) as against one for all other configurations (Figures 8). This exceptional recovery was achieved after 3077days of production as against 1031 days for 2a, 900 days for 3a, 1577 days for 4b, 1474 days for 5a and 536 days for 8a.

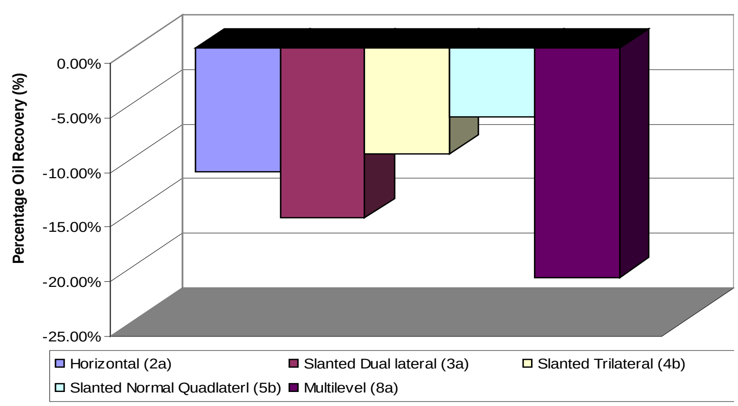


Figure 8: Decremental percentage oil recovery of well configurations be low Vertical Five-Spot (1a).

4 CONCLUSION

The result of this study show that Vertical five-spot (1a) recovered more oil than any of the scenarios considered for multilateral wells. The incremental oil recovery ranged from 6.3% to 20% over the oil recovered by other scenarios although at a slower rate. Normal Quadlateral five-spot (5a) and Dual Lateral line drive (3a) added 13.5% and 13.0% more value respectively over what was obtainable with Vertical five-spot (1a) and were the two most profitable scenarios. This showed that

ISSN 2229-5518
the producibility of multilateral well configurations did not increase proportionally with the number or length of laterals but depended rather on the relative arrangement of the multilateral producers and injectors in a geometric pattern.

REFERENCES

[1] Algharaib, M., and Gharbi, R. B. C., (2005): "A Comparative of Waterflooding Projects Using Horizontal Wells". *Paper SPE 93742*, 2005.

[2] Evans, R., (2001): "Produced Water Management Strategy with the Aid of Decision Analysis". *Paper SPE 66543 presented at the SPE/EPA/DOE Exploration and Production Environmental Conference.* San Antonio, Texas, USA. 2001.

[3] Fanchi, J. R., Harpole, K. J., and Bujnowski, S. W., (1982): Boast: A Three-Dimensional, Three-Phase Black Oil Applied Simulation Tool (Version 1.1). *Keplinger and Associates, Inc. Tulsa, Oklahoma,* USA. September 1982.

[4] Gharbi, R. B., Peters, E. J., and Afzal, N., (1996): "Effect of Heterogeneity on the Performance of Immiscible Displacement with Horizontal Wells". *Paper SPE 35441 presented at the 1996 SPE/DOE* Tenth Symposium on Improved Oil Recovery held in Tulsa Oklahoma, USA. 21-24 April, 1996.

[5] Nestor R., Jerry, L. J., and John, P. S., (2003):"Economic Comparisons of Multilateral and Horizontal Wells in Water-Drive Reservoirs". *Paper SPE 80927 presented at the SPE Production and Operations Symposium held in Oklahoma City, Oklahoma, USA*. 22-25 March, 2003.

[6] Ozkan, E., and Raghaven, R., (1990): "A Breakthrough Time Correlation for Coning Toward Horizontal Wells". *Paper SPE 20964 presented at the Europee 90 Conference, The Hague, Netherlands.* 22-24 October, 1990.

[7] Palsson, B., Davies R., Todd, A. C., and Somerville, J.M., (2003a): "The Water Injection Process: A Technical and Economic Integrated Approach". *TransIChemE,* Volume 81, Part A, March 2003.

[8] Palsson, B., Davies R., Todd, A. C., and Somerville, J.M., (2003): "A Holistic Review of the Water Injection Process". *Paper SPE 82224 presented at the SPE European Formation Damage Conference held in The Hague,* The Netherlands. 13-14 May, 2003.

[9] Palsson, B., Davies R., Todd, A. C., and Somerville, J.M., (2003): "Water Injection Optimized With Statistical Methods". *Paper SPE 84048 presented at the SPE Annual Technical Conference and Exhibition held in Deriver, Colorado, U.S.A.* 5-8 October, 2003.

[10] Raphael, G., and Christine, A. E., (2001): "Single-Well Waterflood Strategy for Accelerating Oil Recovery". Paper SPE 71608 presented at the 2001 SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, USA. 30 September–3 October, 2001.

[11] Ray, H., (1998): *Boast98 and EdBoast:* User's Guide and Documentation Manual. *BDM-Federal, Inc. Tulsa, Oklahoma, USA*. December, 1998.

[12] Shirif, E. and Tarhuni, H., (2002): "Waterflooding Performance of Stratified Reservoirs with Bottom-Water Conditions". *Paper SPE 77965 presented at the SPE Asia Pacific Oil and Gas Conference and Exhibition held in Melbourne, Australia.* 8-10 October, 2002.

[13] Shirif, E., Elkaddifi, K. and Hromek, J. J., (2003):"Waterflood Performance under Bottomwater Conditions: Experimental Approach". Paper SPE 80613, SPEREE, February 2003.

[14] Torrey, P. D., (1950): A Review of Secondary Recovery of Oil in the United States. Secondary Recovery of Oil in the United States,*API, Dallas, USA,* 1950 (1)

[15] www.ipims.com (International Petroleum Industry Multimedia System)

ISSN 2229-5518

APPENDIX 1

Table 2: Water Injection Schemes

Scenario	Case	Injection Wells		Production Wells		Injection Rate, STB/D	Effective Production /Inject-ion Well Ratio (I/P)	Well Pattern	Completion layer	
		No.	Type	No.	Type				Production Well	Injection Well
1	a	9	VT	4	VT	-4496	1	5 SPOT	1-6	1-6
2	a	2	HL	1	HL	-11250	1	LINE	5	10
3	a	2	SDL	1	SDL	-10100	1	LINE	1-6	1-6
4	a	6	TL	3	TL	-9678	2	6 SPOT	5	10
	b	6	SLT	3	STL	-8301	2	6 SPOT	1-6	1-6
5	a	4	NQL	1	QL	-9900	1	5 SPOT	5	10
	b	4	SNQL	1	SQL	-7876	1	5 SPOT	1-6	1-6
6	a	4	RQL	1	IQL	-11828	1	5 SPOT	5	10
	b	4	SRQL	1	SIQL	-10186	1	5 SPOT	1-6	1-6
7	a	4	IQL	1	IQL	-10060	1	5 SPOT	5	10
	b	4	SIQL	1	SIQL	-8560	1	5 SPOT	1-6	1-6
8	a	2	SL	1	SL	-21600	1	LINE	3, 8	3, 8

ISSN 2229-5518

APPENDIX 2

Table 3: Simulation Run Summary

Scenario	Case	Cum. Oil Produced (MSTB)	Cum. Gas Produced (MMSCF)	Cum. Water Produced (MSTB)	Cum. Water Injected (MSTB)	Time to Water Breakthrough, Tb (DAYS)	Time to Ultimate Recovery, Tu (DAYS)	Tb/Tu Ratio	Recovery Factor
1	a	5159	3281	6127	-13659	1077	3035	0.35	0.66
2	a	4636	2949	3973	-11697	505	1040	0.49	0.59
3	a	4468	2841	1590	-9131	540	905	0.60	0.57
4	a	4563	2902	2254	-9686	293	997	0.29	0.58
	b	4709	2995	5237	-13015	347	1568	0.22	0.60
5	a	4832	3073	3070	-11467	341	1157	0.29	0.62
	b	4854	3087	3188	-11483	428	1458	0.29	0.62
6	a	4695	2986	3395	-12349	77	1043	0.07	0.60
	b	4711	2996	3419	-12152	48	1193	0.04	0.60
7	a	4834	3074	4003	-12011	382	1194	0.32	0.62
	b	4831	3072	4058	-12049	420	1407	0.30	0.62
8	a	4268	2714	3553	-11703	268	540	0.50	0.54