SPE SA (add paper id)

Liquids Phase Holdup and Separation Characteristics as a Function of Well Inclination and Flowrate

Mohammad R. Awal[a], Habib D. Zughbi[b], Shaikh A. Razzak[a], Abdulaziz A. Al-Majed[c], and Hasan Y. Al-Yousef[c].
[a]Center for Petroleum and Minerals—The Research Institute; [b]Department of Chemical Engineering; [c]Department of Petroleum Engineering. King Fahd University of Petroleum & Minerals, Dhahran 31261, Saudi Arabia. *Correspondence: mrawal@kfupm.edu.sa*

This paper was prepared for presentation at the 2005 SPE Technical Symposium of Saudi Arabia Section held in Dhahran, Saudi Arabia, 14-16 May 2005.

Abstract

The maturing Middle Eastern oil fields with natural aquifer support or water injection can pose a challenging produced water handling and disposal issues. The increased water-oil ratio also presents productivity problems; many wells will die prematurely due to increased water holdup. The produced water management cost @US$ 0.50—1.00 per barrel involving millions of barrels of water (even at a modest WOR of 50% from current 30-35%) will be in billions due to the high daily oil production rate envisaged. In this paper, we focus on various aspects of downhole oil-water separation, which we believe will lessen the cost significantly. The downhole water separation technology developed and applied in the western hemisphere cannot be directly applied here because of the orders of magnitude higher production rates per well.

Lacking a production flow-loop facility in the region with full-scale production equipment, we use an industry-standard commercial computational fluid dynamics (CFD) simulation tool to investigate inline oil and water separation characteristics under downhole conditions. Specifically, we investigate the startling sensitivity of well inclination in the 80-100 degrees range. We show that it is crucial to control the well inclination within a tight regime to achieve effective and manageable liquids separation in near horizontal wells. We also show that the liquids phase separation in these wells is sensitive to the gross liquids flow rate.

The CFD simulation study reported in this paper will lead to new technology development that can be used to achieve more effective well completion design in near horizontal wells drilled specifically to obtain downhole oil-water separation. The success of such innovative oil-water separation will save many producing wells from dying prematurely and save millions of dollars in produced water handling and disposal.

Introduction

With the advent of horizontal wells in the early 90's, the question of fluids holdup in the deviated and horizontal well sections became important from production well logging point of view (Bamforth et al., 1996; Catala et al., 1996; Theron & Unwin, 1996). Various studies conducted to investigate the effect of well inclinations on oil-water phase hold up inside the pipe stemmed from the concern to determine the accuracy of production tools to determine fluid entries and relative flow rates. From these studies, it was established that vertical wells seldom allow phase separation for wells flowing at moderate to high flow rates. On the other hand, various flow regimes were observed for deviated and horizontal wells. As shown in Figs. 1, there are at least three regimes of flow derived from flow structure variation with well inclination and consequent hold up. For nearly vertical wells (inclination $\pm 20^0$), the oil and water mixes fairly well across the entire pipe cross section, with the lesser phase evenly dispersed. However, as the pipe inclination further increases, the effect of gravity becomes noticeable, with a higher concentration of oil in the upper section of the pipe. With angles above 20^0 and below 85^0, the monophasic oil zone gradually increases with a corresponding narrowing of the mixed zone. Thereafter, in the $85\text{-}90^0$ range, flow becomes completely stratified, with little or no mixed zone.

These remarkable findings on fluids holdup in the deviated pipe sections also paved the way for considering in-line and downhole oil-water separation (DOWS). The need for DOWS was also accentuated by the increased producing water-oil ratios (WOR) in many maturing oil fields in the world. The high WOR not only meant an increase in oil production costs due to water treatment and disposal requirements, but also reduced oil production rate.

Worldwide daily water production rate in 1999 was about 210 million bpd (33.4 m^3/d), which was approximately 3 times the oil production (Bailey et al., 2000). The average cost of treatment and disposal of produced water vary from US$ 0.15 to $\$15/m^3$, depending on location and volumetric throughput (Khatib & Verbeek, 2002), with average cost in the US being

\$0.1/bbl (\$0.6/m^3). Besides the direct costs associated with lifting (ESP, etc.), transport (pipeline) and treatment (plant, chemicals, etc.) and re-injection, there may be indirect costs, such as lost or deferred oil production. While there are water shut-off techniques (mechanical and chemical), the best option, where feasible, would be to separate and re-inject the water downhole. The downhole oil-water separation (DOWS) is a mature technology in the western hemisphere. As of 1999, fewer than 50 DOWS had been installed in the world (Veil et al., 1999).

DOWS technology reduces the quantity of produced water that is handled at the surface by separating it from the oil downhole and simultaneously injecting it underground. The two primary components of a DOWS system are an oil/water separation system and at least one pump to lift oil to the surface and inject the water. Two basic types of DOWS have been developed – one type using hydrocyclones to mechanically separate oil and water and one relying on gravity separation that takes place in the wellbore (Veil et al., 2000).

While DOWS technology has been applied successfully in the US and Canada, one thing should be kept in mind that all these wells produced only a few barrels of oil/water per day (bopd). For application in the Middle East, where typical oil production rate is in several thousand bpd, the success of these DOWS technology is yet to be proven.

The purpose of this paper is to investigate if the long horizontal wells offer benefits of downhole gravity separation in high throughput wells. For downhole study, experimental procedure based on actual well tests is thought to be cost prohibited, if not downright impractical. A surface flow-loop is also very costly to set up and maintain, besides being tedious and cumbersome for running experiments with high pressure, temperature, and pipe dimensions (often requiring large open space exposed to the elements). Therefore, we resort to numerical simulations based on state-of-the-art CFD technology.

DOWS Modeling Using Computational Fluid Dynamics

One of the earliest oil-water phase holdup modeling study was reported by Theron and Unwin (1996). They did not focus on the issue of achieving DOWS but the effect of logging tool positions (centered or eccentric in the deviated well). Using a simple numerical model with wall and interface shear terms, they claimed to have matched the oil-water holdup data observed in flow-loop experiments.

Our intention is to focus on the well inclination and flow rate conditions toward achieving as much DOWS as possible. Therefore, using a state-of-the-art multiphase flow model is of paramount importance. After reviewing the published literature, we believe there exists a few commercial computational fluid dynamics (CFD) simulators capable of accurately modeling downhole oil-water separation. The ability to represent complex flow geometry by using the CAD tool associated with a commercial CFD package, it is possible to create a virtual well. The CAD tool enables creating automatic grid (mesh) generation over the flow domain. The powerful finite element or finite volume based solver solves the PDEs describing the mass transfer, turbulence and heat transfer equations for both transient and steady state conditions. By prescribing appropriate initial and boundary conditions, as well as fluid properties, virtually any flow scenario can be simulated. In our CFD simulation study we have used the **Fluent**® package. Out of several multiphase flow models available in this simulator, we chose the *Eulerian-Eulerian* model, which is computationally most comprehensive but more suitable for multiphase systems with the dispersed phase exceeding 10% v/v.

The base case model for our CFD simulation study is a horizontal well. As indicated in the literature review above, that is where in-line separation of oil and water is expected. First we will investigate the flow behavior in a standard perforated completion. The well completion schematic is shown in Fig. 2a. We run the problem in 3D using the standard κ–ε turbulence model due to high superficial velocity expected in the high flow throughput in the well`. The following data are used to construct the model geometry, grid, and run the simulation.

Well diameter OD (ID):	7.0 in. (6.3 in.)
Perforation diameter & density:	1 in. & 3 SPF.
Perforation interval:	5 ft.
Disposal section length:	50 ft.
Production section length:	15 ft.
No. of tetrahedral grids:	~ ½ millions.
Producing WOR at inlet perforations:	65:35
Oil viscosity (μ_o) = 2.3 cp (0.0023 Pa.s).	
Water viscosity (μ_w) = 1.0 cp (0.001 Pa.s).	
Oil density (ρ_o) = 850 kg/m^3	
Water density (ρ_w) = 1,050 kg/m^3.	
Boundary conditions at CFD model inlet and outlets:	Pressures

The high number of grids (~ ½ millions) is required to capture the spatial distribution of the two liquid phases accurately. This, however, increases the time required to achieve solution convergence.

We use a high WOR because conventional DOWS technology is invoked when producing WOR becomes high. Fig. 2b shows the phase separation or mixing. The oil phase is shown in red, while water is indicated by the blue color in the phase volume fraction contour map. Clearly the perforated interval is a turbulent zone due to fluid influx in jets through the perforations.

Fig. 2c shows the phase distribution as the fluids move up along the 45^o production casing. The upper section is a mixed zone (greenish: ~40-45% v/v oil), with predominantly oil in the lower section (bluish). This indicates the possibility of obtaining better phase separation in the horizontal disposal section where there is no perforation. This is confirmed as we move down the well: a stable phase separation is observed, as shown in Fig. 2d. As the oil and water flows down the *smooth* (i.e., no perforation or other obstructions) well, the two phases separate and the separation is maintained down the well.

Changing the inlet and outlet boundary pressure conditions can modify the flow split. However, the sensitivity of operating pressures will not be covered in the present study.

We also observe a mixed zone separating the upper oil and the bottom water zones. The mixed zone can also be an oil-water emulsion (with water-in-oil emulsion in the upper part of the mixed zone above an oil-in-water emulsion below). Emusification is usually expected in a high velocity, turbulent flow regime, accentuated by relatively higher oil viscosity and also a smaller oil-water density difference. However, the multiphase flow model in the CFD package, **Fluent®**, does not incorporate emu lsion.

Effect of Horizontal Well Inclinations

At this point, it is worthwhile to investigate the effect of well inclination around 90^0. We take two cases: a 89^0 inclined well where the fluid is flowing updip, and a 91^0 well where the fluid is flowing downdip. To evaluate the effect of gravity (density) and well inclination alone, we take a case where the volumetric oil/water ratio is unity (50:50), i.e., equal throughput for each of the two phases.

Intuitively, the updip flow (89^0 inclination) is expected to promote the flow of the lighter phase, viz. oil. This translates into a higher superficial velocity of oil than the water phase superficial velocity. If the two phase have equal viscosity, then the slower moving phase should occupy more of the cross sectional area of the pipe, resulting in higher holdup for the heavy phase (water).

On the other hand, the downdip flow (91^0 inclination) should show the opposite effect, i.e., greater holdup for the lighter phase (oil), since gravity would assist downward flow of the heavier phase (water) in this case.

The following oil and water properties are used:

Oil-water flow rate ratio at inlet (q_o/q_w)	= 50:50
Total flow rate	= 600 bpd
Oil viscosity (μ_o)	= 2.3 cp (0.0023 Pa.s).
Water viscosity (μ_w)	= 1.0 cp (0.001 Pa.s).
Oil density (ρ_o)	= 850 kg/m^3
Water density (ρ_w)	= 1,050 kg/m^3.

Boundary conditions at CFD model inlet and outlets: velocity inlet, outflow boundary.

Fig. 3 shows the effect of well inclinations on phase holdup and separation. We analyze the case for a moderate gross fluid flow rate of 600 bpd. For the present cases, the difference of only 1^0 in inclination gives a clearly noticeable difference in holdup. Correspondingly, the oil phase velocity is expected to increase from downdip to updip flow, which is clearly shown. Remember, this differential velocity results in opposite direction to the differential phase holdup due to the fact that a 50:50 oil-water throughput is used.

Effect of Gross Flow Rate

As the total throughput in the constant cross sectional pipe increases, the superficial velocities of each phase also increases, inducing turbulence. This turbulence destabilizes the segregated flow interface achieved at lower throughput. Fig. 4 shows this effect of high flow rate clearly. Whereas Fig. 3 showed the phase separation at a gross flow rate of approx. 440 bpd, Fig. 4 shows pulling of water into the upper oil phase as the gross fluid rate is increased to 2,200 and 4,440 bpd.

Conclusions

The findings of experimental and numerical studies conducted in the 90's to determine the effect of oil and water holdup in deviated wells on production logs have laid the ground work for achieving in-line and also downhole oil-water separation. We have conducted numerical simulation studies with a state-of-the art CFD simulation package to study the effects of well inclination, especially the sensitivity around 90 degrees (horizontal), and gross liquid flow rate. The limited flow scenarios used in these simulation runs indicate that while a good DOWS is possible in near horizontal wells, the efficiency of separation is affected by both these parameters. Probably more significant is the effect of flow rate, which can be controlled from surface by adjustable choke. A a full-scale (in terms of well dimension and operating pressure range) CFD model can become a design engineer's essential tool now in order to determine the optimum mix of well inclination and flow rate for achieving maximum oil recovery in a downhole gravity separation scheme for a specific oil-water system.

The CFD simulation approach reported in this paper has the potential to improve the existing DOWS technology, especially for high rate wells. Additionally, production wells that may prematurely die because of high WOR can get extra lease of life and add to the bottom line.

Nomenclature

q_o : oil flow rate, bpd (m^3/s)
q_w : water flow rate, bpd (m^3/s)
Q: total flow rate, bpd (m^3/s)
v_o: oil-phase superficial velicity, ft/min (m/s)
v_w: water-phase superficial velicity, ft/ min (m/s)
v: average superficial velicity, ft/ min (m/s)
μ_o: oil viscosity, cp (Pa.s)
μ_w: water viscosity, cp (Pa.s)
ρ_o oil density, lb/ft^3 (kg/m^3)
ρ_w water density, lb/ft^3 (kg/m^3)

Acknowledgements

The authors thank KFUPM-RI for permission to publish the paper.

References

1. Bailey, W., Crabree, M., Tyrie, J., Elphick, J., Kuchucuk, F., Romano, C. and Roodhart, L. (2000). Water Control, in Oilfield Review Sclulberger, Spring 2000.

2. Khatib, Z. and Verbeek, P. (2002). Water to value—Produced water management for sustainable field development of mature and green fields. SPE paper

No. 73853 presented at SPE Intl. Conf on HSE in Oil & Gas Expl. & Prodn., Kuala Lumpur, Malaysia, 20-22 March 2002.

3. Veil, J.A., B.G. Langhus, and S. Belieu (1999). Feasibility Evaluation of Downhole Oil/Water Separation (DOWS) Technology. Report prepared for U.S. Department of Energy, Office of Fossil Energy, National Petroleum Technology Office, by Argonne National Laboratory, CH2M-Hill, and Nebraska Oil and Gas Conservation Commission, January.

4. Veil, J.A. (2000). Summary of Data from DOE-Subsidized Field Trial #1 of Downhole Oil/Water Separator Technology. Report Prepared for U.S. Department of Energy. Argonne National Laboratory Contract No. W-31-109-Eng-38. p. 4.

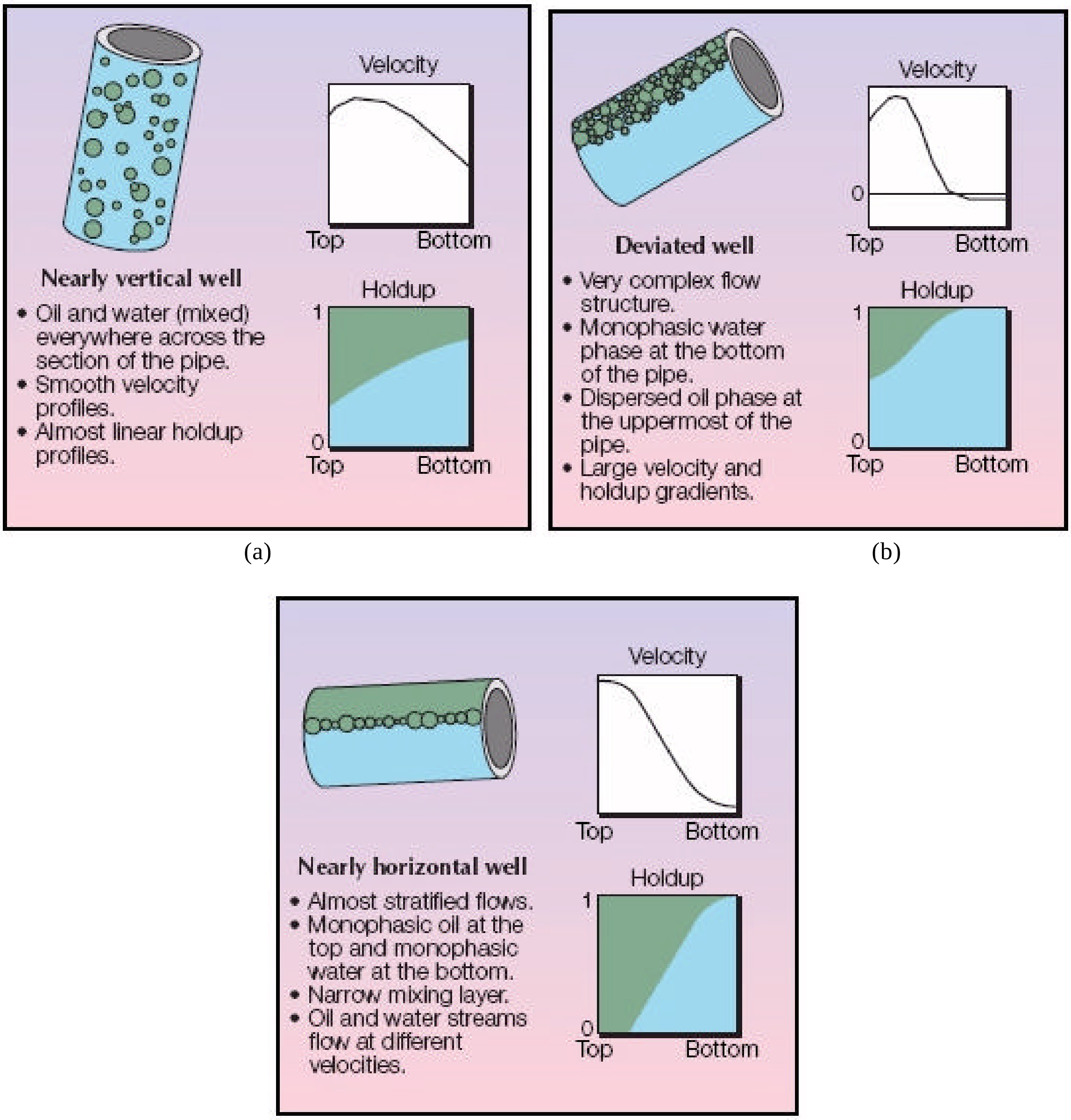
5. Bamforth, S., Besson, C., Stephenson, K., Whittaker, C., Brown, G., Catala, G., Roualt, G., Theron, B., Conot, G., Lenn, C., and Roscoe, B. (1996). "Revitalizing Production Logging". Oilfield Review, Winter 1996. pp.44-60.

6. Theron, B.E. and Unwin, T. (1996). "Starified flow model and interpretation in horizontal wells," SPE 36560.

7. Catala, G., Theron, B., Conort, G., and Ferguson, J. (1996). "Fluid flow fundamentals," Oilfield Review, Winter 1996. pp.61-64.

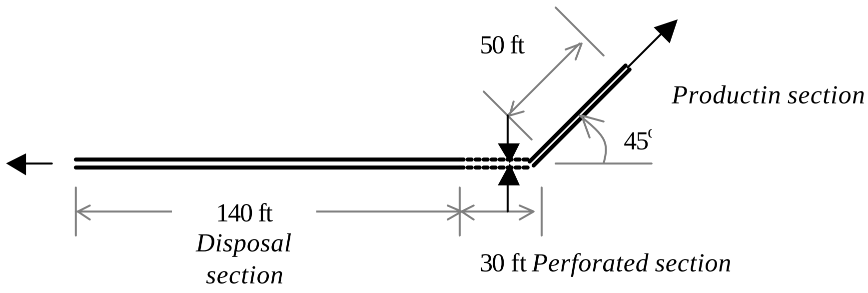
SI Metric Conversion Factors

cp * 1.0	E-03 = Pa.s
bpd * 1.84	E-06 = m^3/s
ft/min * 5.08	E-03 = m/s



(c)

Figure 1. Flow regimes in oil-water flow, as a function of well inclinations: (a) Vertical: 0^0-20^0; (b) Deviated: 20^0-85^0; and (c) Horizontal: 85^0-90^0. (Ref. Catala et al., 1996).



(a)

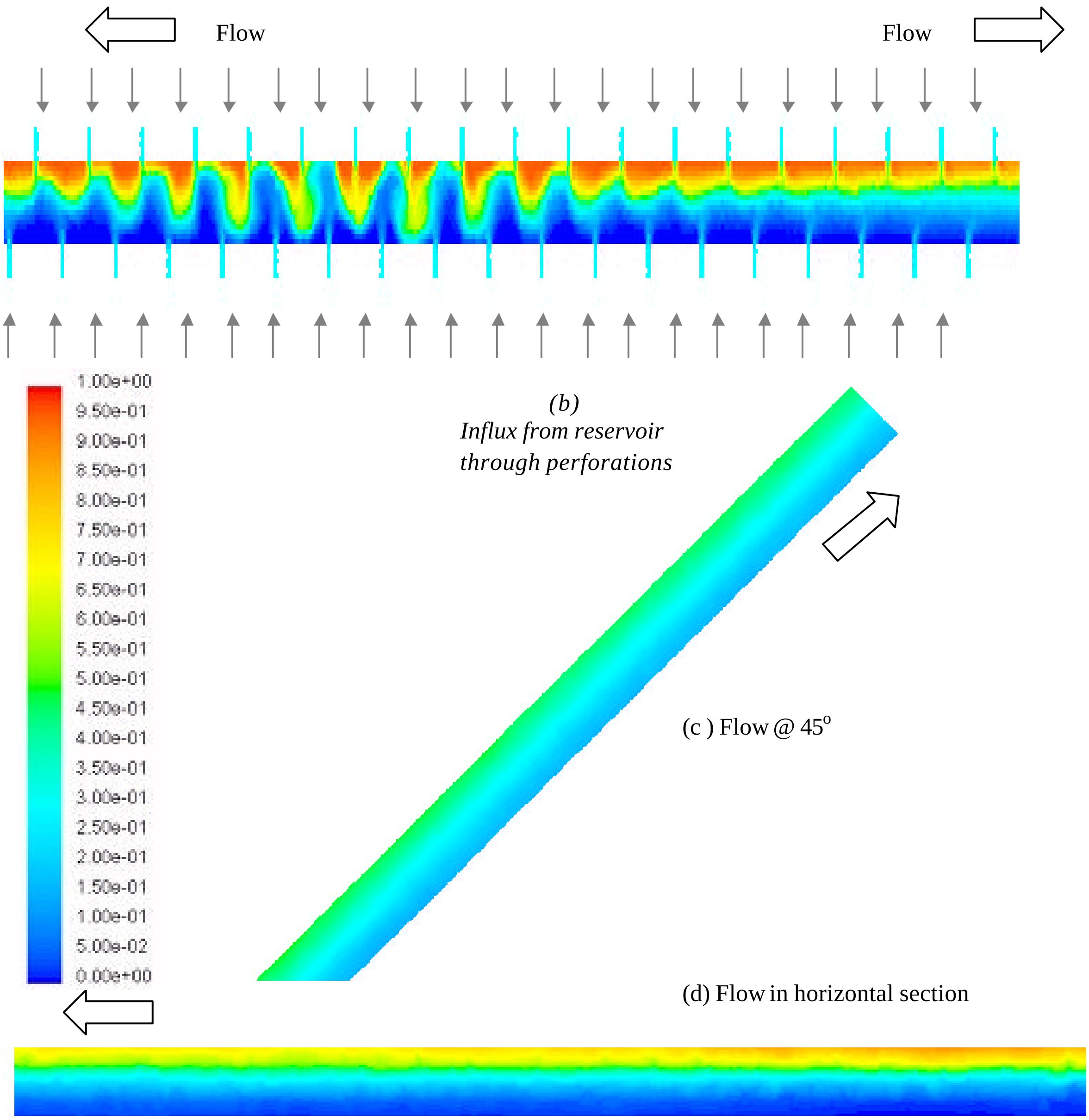


Figure 2 (a) Model geometry, showing a 30 ft *perforated interval* for influx from reservoir; a 140-ft *horizontal section*, and a 50-ft *inclined section* for oil production (with some water).
Contours of the volume fraction of oil and water in the (b) 30-ft near-horizontal perforated section (1.0→ 100% oil; 0.0→ 100% water); (c) non-perforated, 50-ft section of 45^{o}-inclined well side; (d) non-perforated, 140-ft section of horizontal well side

.

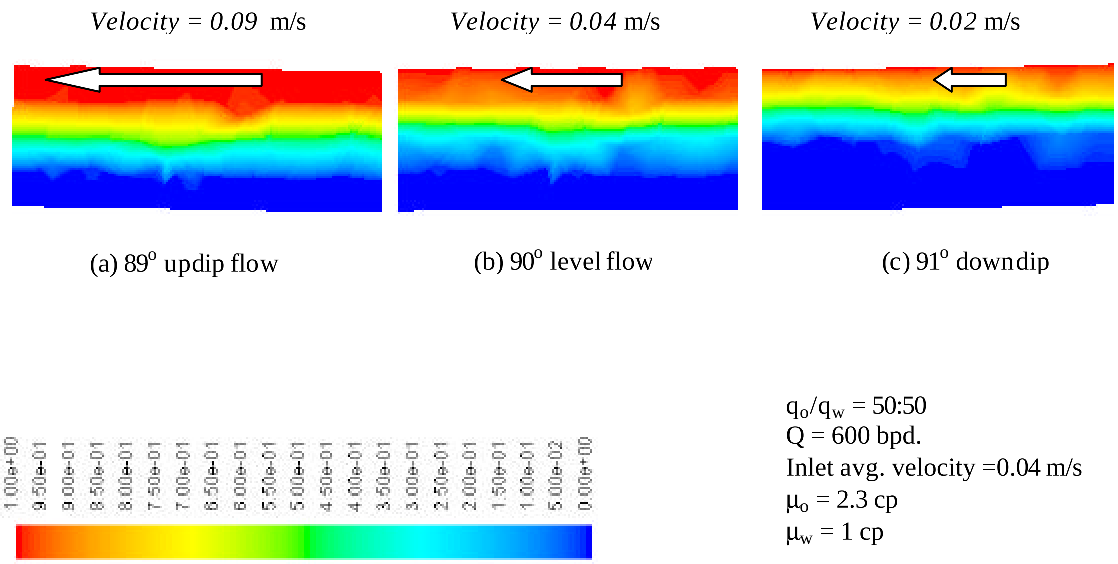


Figure 3: Effect of well inclination: (a) 89^0; (b) 90^0; (c) 91^0. Contours of the oil volume fraction in 100-ft section of horizontal well. Note the increased oil velocity near the top of pipe as flow direction changes from downdip to updip The white arrow length is roughly proportionate to velocity magnitude.

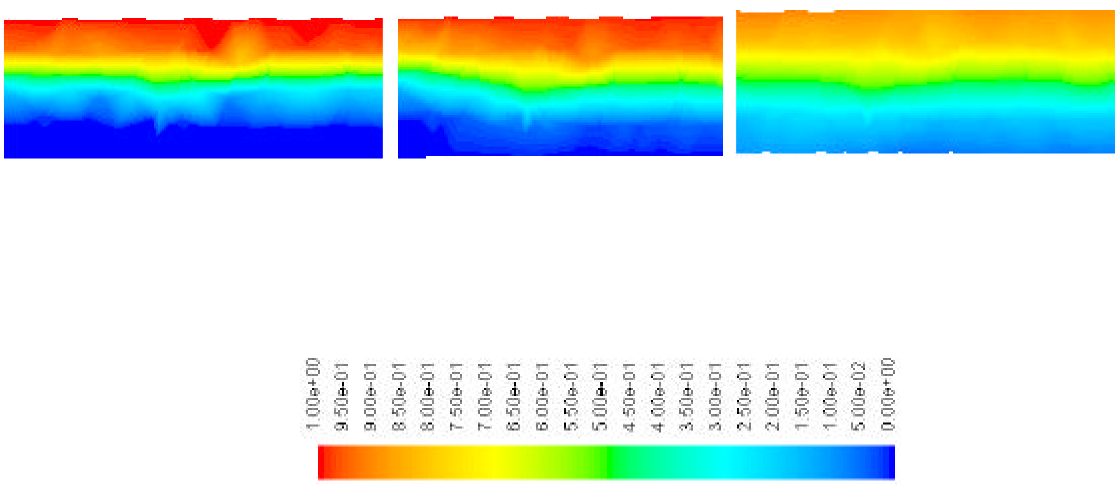


Figure 4: Effect of fluid flow rate on phase holdup and separation. Contours show the oil volume fraction in 100-ft section of horizontal well (inclination = 90 degree).