CONTROL OF WATER CONING IN OIL AND GAS WELLS

(Final Project Report)

Submitted for Partial Fulfillment of the

BACHELOR OF TECHNOLOGY

(APPLIED PETROEUM ENGINEERING)

SUBMITTED TO:

UNIVERSITY OF PETROLEUM AND ENERGY STUDIES

Under the Guidance of:

ASSISTANT PROF. A. K. CHAUBEY

Submitted By:-

Sahil Singh (R010203002)
Naveen Bahukhandi (R010203014)

CERTIFICATE

This is to certify that the project work on ***"CONTROL OF WATER CONING IN OIL AND GAS WELLS"*** submitted to University of Petroleum & Energy Studies, Dehradun, by **Mr. Sahil Singh & Mr. Naveen Bahukhandi**, in partial fulfillment of the requirement for the award of **Degree of Bachelor of Technology in Applied Petroleum Engineering** (Academic Session 2003 – 2007) is a bonafide work carried out by them under my supervision and guidance. This work has not been submitted anywhere else for any other degree or diploma.

Date: - 7 May 2007

Prof. A.K. Choubey
(Assistant Professor)

Acknowledgement

With great pleasure we would like to express our sincere thanks to ***University of Petroleum & Energy Studies, Dehradun*** for giving us opportunity to carry out our final project work on the project ***"Control of water coning in oil gas wells"***, in the due course of our B-Tech Program.

We are deeply indebted to ***Dr. B.P. Pandey, Dean, College of Engineering,University of Petroleum & Energy Studies, Dehradun*** for his invaluable and eruditeguidance, keen interest and constructive suggestions, timely and generous help beyond measure at all the stages during the progress of the project work.

We are also very grateful to ***Mr. A.Chaubey (Assistant professor, U.P.E.S.)*** who guided us at each step during our project work. His much needed guidance and support provided us a solid platform for undergoing the process of learning during our project work.

Our sincere gratitude to ***Mr. Sanjeev Kumar (Senior librarian U.P.E.S., Dehradun)*** for his generous support in providing access to relevant literatures on the given topic from the **library.**

Sahil Singh Sahil Singh 7/05/07

Naveen Bahukhandi 7/5/07

Abstract

Presented in this project report are recently experimental and theoretical advancements in coning reversal technique using an innovative completion method with down water sink (DWS). In this technique a well is dual completed in oil and water columns with a packer separating the two completions. Then an inverse cone is created by draining the water from the water sink completion below oil water contact while producing water free oil from the completion. The experiments were performed with a physical model that visualized all stages of water cone development , reversal , and creation of inverse cone. Results shown in this project report shows the effect of DWS design parameters on the reverse coning performance. Theoretical part of this report employed mathematical model .The results showed how the productivity of a 'watered out' well can be recovered to give a significant production of oil. Also, the oil produced from the well with DWS completed water was free. The results indicate that oil production from wells with DWS completions under condition of coning reversal may have high economic merit and is technically feasible.

TABLE OF CONTENTS

1. CONING

1.1 INTRODUCTION

Coning is a term used to describe the mechanism underlying the upward movement of water and/or the down movement of gas into the perforations of a producing well. Coning can seriously impact the well productivity and influence the degree of depletion and the overall recovery efficiency of the oil reservoirs. The specific problems of water and gas coning are listed below.

• Costly added water and gas handling

• Gas production from the original or secondary gas cap reduces pressure
without obtaining the displacement effects associated with gas drive

• Reduced efficiency of the depletion mechanism

• The water is often corrosive and its disposal costly

• The afflicted well may be abandoned early

• Loss of the total field overall recovery

Delaying the encroachment and production of gas and water are essentially the controlling factors in maximizing the field's ultimate oil recovery. Since coning can have an important influence on operations, recovery, and economics, it is the objective of this chapter to provide the theoretical analysis of coning and outline many of the practical solutions for calculating water and gas coning behavior.

1.2 MECHANISM OF CONING

Coning is primarily the result of movement of reservoir fluids in the direction of least resistance, balanced by a tendency of the fluids to maintain gravity equilibrium. The analysis may be made with respect to either gas or water. Let the original condition of reservoir fluids exist as shown schematically in Figure 1, water underlying oil and gas overlying oil. For the purposes of discussion, assume that a well is partially penetrating the formation (as shown in Figure 1) so that the production interval is halfway between the fluid contacts. Production from the well would create pressure gradients that tend to lower the gas-oil contact and elevate the water-oil contact in the immediate vicinity of the well. Counterbalancing these flow gradients is the tendency of the gas to remain above the oil zone because of its lower density and of the water to remain below the oil zone because of its higher density. These counterbalancing forces tend to deform the gas-oil and water-oil contacts into a bell shape as shown schematically in Figure 9-2. There are essentially three forces that may affect fluid flow distributions around the well bores. These are:

- Capillary forces
- Gravity forces
- Viscous forces

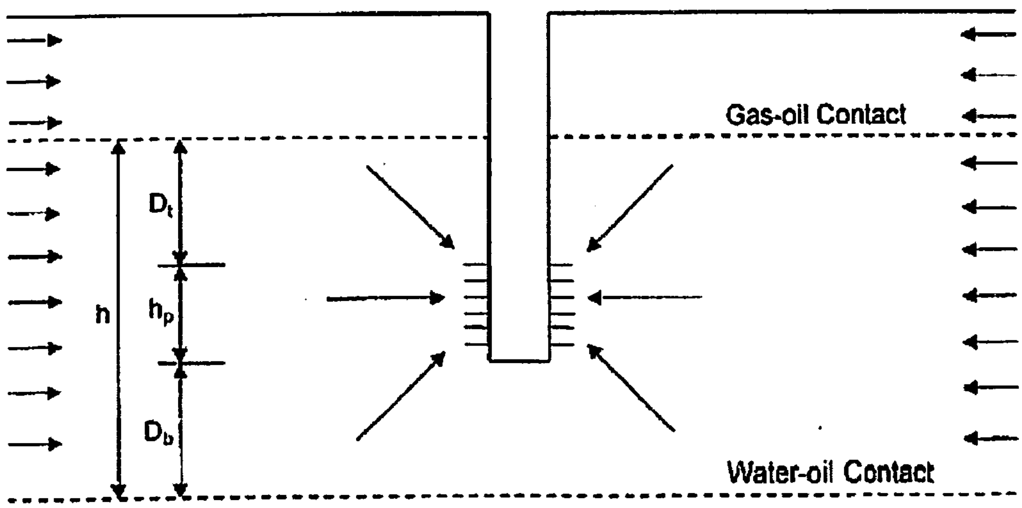


Figure 1: Original reservoir static condition

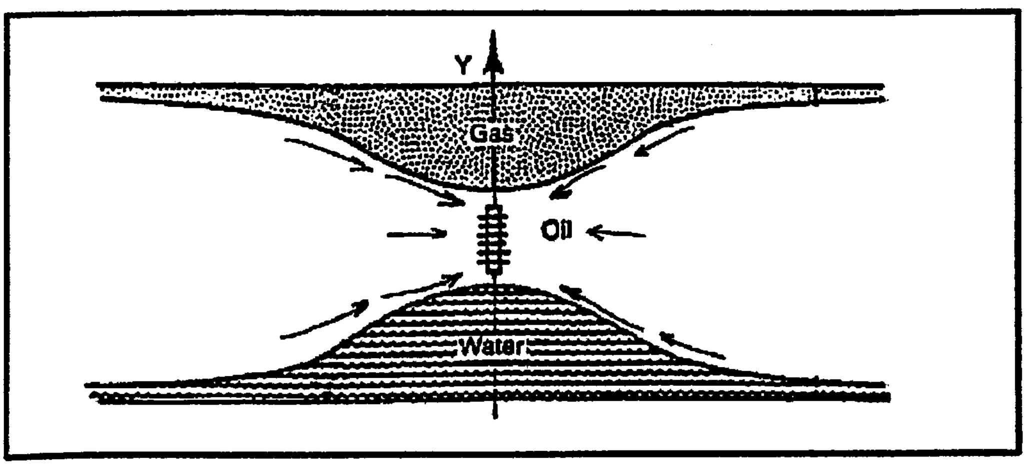


Figure 2: Gas and water coning.

Capillary forces usually have negligible effect on coning and will be neglected. Gravity forces are directed in the vertical direction and arise from fluid density differences. The term viscous forces refers to the pressure gradients associated fluid flow through the reservoir as described by Darcy's Law. Therefore, at any given time, there is a balance between gravitational and viscous forces at points on and away from the well completion interval. When the dynamic (viscous) forces at the wellbore exceed gravitational forces, a "cone" will ultimately break into the well.

1.3 TYPES OF CONING PROFILE

- Stable cone
- Unstable cone
- Critical production rate

If a well is produced at a constant rate and the pressure gradients in the drainage system have become constant, a steady-state condition is reached. If at this condition the dynamic (viscous) forces at the well are less than the gravity forces, then the water or gas cone that has formed will not extend to the well. Moreover, the cone will neither advance nor recede, thus establishing what is known as a stable cone. Conversely, if the pressure in the system is an unsteady-state condition, then an unstable cone will continue to advance until steady-state conditions prevail. If the flowing pressure drop at the well is sufficient to overcome the gravity forces, the unstable cone will grow and ultimately break into the well. It is important to note that in a realistic sense, stable system cones may only be "pseudo-stable" because the drainage system and pressure distributions generally change. For example, with reservoir depletion, the water-oil contact may advance toward the completion interval, thereby increasing chances for coning. As another example, reduced productivity due to well damage requires a corresponding increase in the flowing pressure drop to maintain a given production rate. This increase in pressure drop may force an otherwise stable cone into a well. The critical production rate is the rate above which the flowing pressure gradient at the well causes water (or gas) to cone into the well. It is, therefore, the maximum rate of oil production without concurrent production of the displacing phase by coning. At the critical rate, the builtup cone is stable but is at a position of incipient breakthrough. Defining the conditions for achieving the maximum water-free and/or gas-free oil production rate is a difficult problem to solve. Engineers are frequently faced with the following specific problems:

1. Predicting the maximum flow rate that can be assigned to a completed well without the simultaneous production of water and/or free-gas.
2. Defining the optimum length and position of the interval to be perforated in a well in order to obtain the maximum water and gas-free production rate.

Calhoun pointed out that the rate at which the fluids can come to an equilibrium level in the rock may be so slow, due to the low permeability or to capillary properties, that the gradient toward the wellbore overcomes it. Under these circumstances, the water is lifted into the wellbore and the gas flows downward, creating a cone as illustrated in Figure-2. Not only is the direction of gradients reversed with gas and oil cones, but the rapidity with which the two levels will balance will differ. Also, the rapidity with which any fluid will move is inversely proportional to its viscosity, and, therefore, the gas has a greater tendency to cone than does water. For this reason, the amount of coning will depend upon the viscosity of the oil compared to that of water. It is evident that the degree or rapidity of coning will depend upon the rate at which fluid is withdrawn from the well and upon the permeability in the vertical direction kv compared to that in the horizontal direction kh. It will also depend upon the distance from the wellbore withdrawal point to the gas-oil or oil-water discontinuity.

The elimination of coning could be aided by shallower penetration of wells where there is a water zone or by the development of better horizontal permeability. Although the vertical permeability could not be lessened, the ratio of horizontal to vertical flow can be increased by such techniques as acidizing or pressure parting the formation. The application of such techniques needs to be controlled so that the effect occurs above the water zone or below the gas zone, whichever is the desirable case. This permits a more uniform rise of a water table. Once either gas coning or water coning has occurred, it is possible to shut in the well and permit the contacts to restabilize. Unless conditions for rapid attainment of gravity equilibrium are present, restabilization will not be extremely satisfactory. Fortunately, bottom water is found often where favorable conditions for gravity separation do exist. Gas coning is more difficult to avoid because gas saturation, once formed, is difficult to eliminate.

There are essentially three categories of correlation that are used to solve the coning problem. These categories are:

- Critical rate calculations
- Breakthrough time predictions
- Well performance calculations after breakthrough

1.4 CRITICAL RATES CALCULATIONS

Critical rate Qoc is defined as the maximum allowable oil flow rate that can be imposed on the well to avoid a cone breakthrough. The critical rate would correspond to the development of a stable cone to an elevation just below the bottom of the perforated interval in an oil-water system or to an elevation just above the top of the perforated interval in a gas-oil system. There are several empirical correlations that are commonly used to predict the oil critical rate, including the correlations of:

- **Meyer-Garder**
- **Chierici-Ciucci**

The practical applications of these correlations in predicting the critical oil flow rate are presented below.

1.4.1 The Meyer-Garder Correlation

Meyer and Garder (1954) suggest that coning development is a result of the radial flow of the oil and associated pressure sink around the wellbore. In their derivations, Meyer and Garder assume a homogeneous system with a uniform permeability throughout the reservoir, i.e., k_o,k_v. It should be pointed out that the ratio kh/kv is the most critical term in evaluating and solving the coning problem. They developed three separate correlations for determining the critical oil flow rate:

- Gas coning
- Water coning
- Combined gas and water coning

Meyer and Garder correlated the critical oil rate required to achieve a stable gas cone with the following well penetration and fluid parameters:

- Difference in the oil and gas density
- Depth Dt from the original gas-oil contact to the top of the perforations
- The oil column thickness h

The well perforated interval hp, in a gas-oil system, is essentially defined as

$h_p = h - D_t$

Meyer and Garder propose the following expression for determining the oil critical flow rate in a gas-oil system:

$Q_{oc} = 0.246*10^{-4} \ (\rho_0 - \rho_g / \ln(r_e / r_w))*(k_o / \mu_o \beta_o)(h^2 - (h - D_t)^2)$

Where:

Q_{oc} = critical oil rate, STB/day

ρ_g, ρ_o = density of gas and oil, respectively, lb/ft3

ko = effective oil permeability, md

r_e, r_w = drainage and wellbore radius, respectively, ft

h = oil column thickness, ft

D_t = distance from the gas-oil contact to the top of the perforations, ft

1.Water coning

Meyer and Garder propose a similar expression for determining the critical oil rate in the water coning system shown schematically in Figure 9-4.

The proposed relationship has the following form:

Q_{oc} $=0.246*10^{-4}$ $(\rho_w - \rho_o / \ln(r_e/r_w))*(k_o/\mu_o\,\beta_o)(h^2 - h_p)$

Where

ρ_w = water density, lb/ft3

h_p = perforated interval, ft

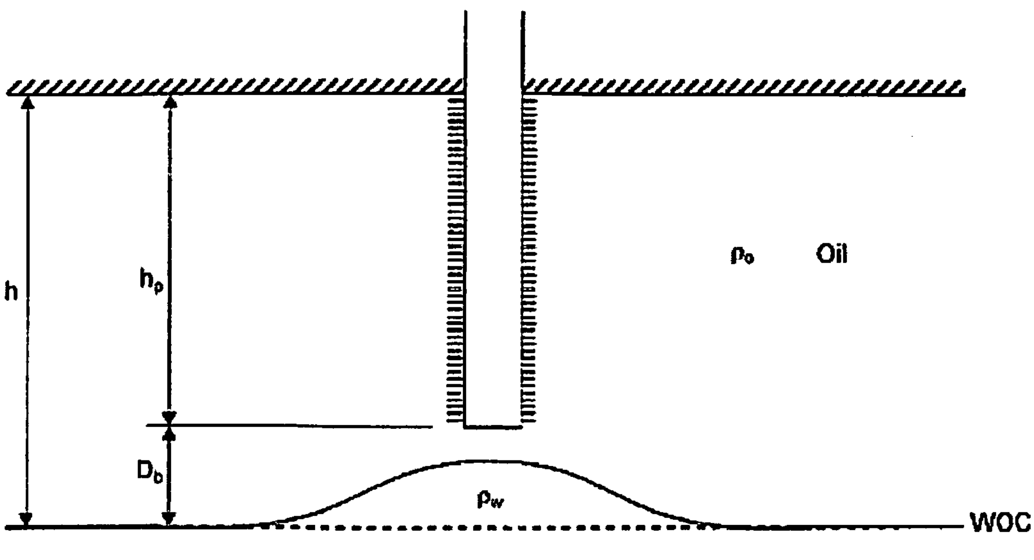


Figure 3: water coning

2.Simultaneous gas and water coning

If the effective oil-pay thickness h is comprised between a gas cap and a water zone (Figure 9-5), the completion interval hp must be such as to permit maximum oil-production rate without having gas and water simultaneously produced by coning, gas breaking through at the top of the interval and water at the bottom. This case is of particular interest in the production from a thin column underlaid by bottom water and overlaid by gas.For this combined gas and water coning, Pirson (1977) combinedEquations 1 and 2 to produce the following simplified expression for determining the maximum oil-flow rate without gas and water coning:

$$Q_{OC} = 0.246*10^{-4} (k_o / \mu_o \beta_o)(h^2 - h_p / \ln(r_e/r_w))*(\rho_o - \rho_w) (\rho_o - \rho_g / \rho_w - \rho_g)^2$$
$$+ (\rho_o - \rho_g) (1 - (\rho_o - \rho_g / \rho_w - \rho_g)^2)$$

Slider (1976) presented an excellent overview of the coning problem and the above-proposed predictive expressions. Slider points out that Equations 1 through 4 are not based on realistic assumptions. One of the biggest difficulties is in the assumption that the permeability is the same in all directions. As noted, this assumption is seldom realistic. Since sedimentary formations were initially laid down in thin, horizontal sheets, it is natural for the formation permeability to vary from one sheet to another vertically. Therefore, there is generally quite a difference between the permeability measured in a vertical direction and the permeability measured in a horizontal direction. Furthermore, the permeability in the horizontal direction is normally considerably greater than the permeability in the vertical direction. This also seems logical when we recognize that very thin, even microscopic sheets of impermeable material, such as shale, may have been periodically deposited. These permeability barriers have a great effect on the vertical flow and have very little effect on the horizontal flow, which would be parallel to the plane of the sheets.

1.4.2 The Chierici-Ciucci Approach

Chierici and Ciucci (1964) used a potentiometric model to predict the coning behavior in vertical oil wells. The results of their work are presented in dimensionless graphs that take into account the vertical and horizontal permeability. The diagrams can be used for solving the following two types of problems:

a. Given the reservoir and fluid properties, as well as the position of and length of the perforated interval, determine the maximum oil production rate without water and/or gas coning.

b. Given the reservoir and fluids characteristics only, determine the optimum position of the perforated interval.

The authors introduced four dimensionless parameters that can be determined from a graphical correlation to determine the critical flow rates. The proposed four dimensionless parameters are shown in Figure 4 and defined as follows:

Effective dimensionless radius r_{De}:

The first dimensionless parameter that the authors used to correlate results of potentiometric model is called the effective dimensionless radius and is defined by:

$r_{De} = (K_h / K_v)^{0.5}$

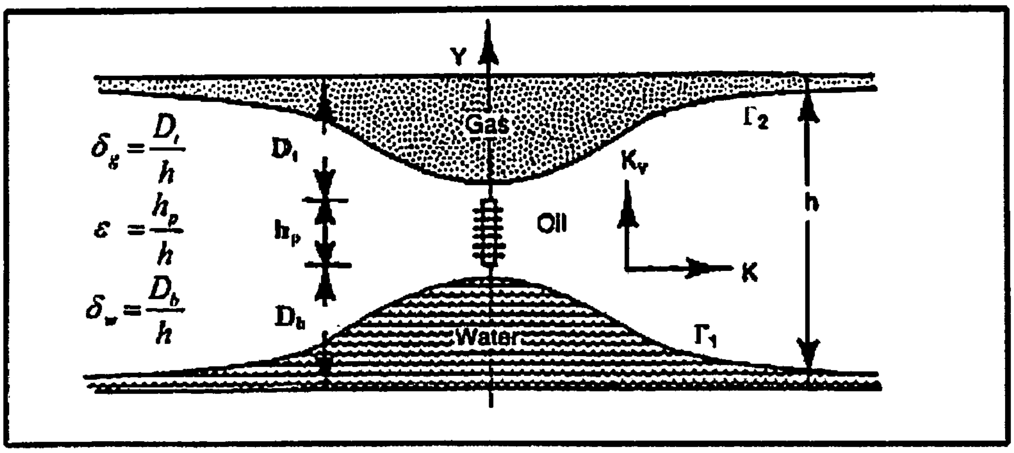


Figure-4

Meyer and Garder stated that the proposed graphical correlation is valid in the following range of r_{De} values:

$5 \le r_{De} < 80$

where

h = oil column thickness, ft

r_e = drainage radius, ft

k_v, k_h = vertical and horizontal permeability, respectively

1. Dimensionless perforated length:

The second dimensionless parameter that the authors used in developing their correlation is termed the dimensionless perforated length and is defined by:

$\varepsilon = h_p / h$

The authors pointed out that the proposed graphical correlation is valid when the value of the dimensionless perforated length is in the following range:

$0 < \varepsilon < 0.75$

Dimensionless gas cone ratio δ_g :

The authors introduced the dimensionless gas cone ratio as defined by the following relationship:

$\delta_g = D_t / h$

with $0.070 < \delta_g \le 0.9$

where:

Dt is the distance from the original GOC to the top of perforations, ft.

Dimensionless water cone ratio δ_w:

The last dimensionless parameter that Chierici et al. proposed in developing their correlation is called the dimensionless water-cone ratio and is defined by:

$$\delta_w = D_b / h$$

with $0.07 < \delta_w \leq 0.9$

where

D_b = distance from the original WOC to the bottom of the perforations, ft

Chierici and coauthors proposed that the oil-water and gas-oil contacts are stable only if the oil production rate of the well is not higher than the following rates:

$$Q_{ow} = 0.492 * 10^{-4} h^2 (\rho_w - \rho_o)(K_{ro} K_h) \psi_{w(r_{De}\, \varepsilon\, \delta_w)} / B_O u_o$$

$$Q_{og} = 0.492 * 10^{-4} h^2 (\rho_o - \rho_g)(K_{ro} K_h) \psi_{g\,(r_{De}\, \varepsilon\, \delta_w)} / B_O u_o$$

where

Qow = critical oil flow rate in oil-water system, STB/day

Qog = critical oil flow rate in gas-oil system, STB/day

The authors provided a set of working graphs for determining the dimensionless function from the calculated dimensionless parameters. This set of curves should be only applied to homogeneous formations. It should be noted that if a gas cap and an aquifer are present together, the following conditions must be satisfied in order to avoid water and free-gas production.

1.5 BREAKTHROUGH TIME

Critical flow rate calculations frequently show low rates that, for economic reasons, cannot be imposed on production wells. Therefore, if a well produces above its critical rate, the cone will break through after a given time period. This time is called time to breakthrough t_{bt}. Two of the most widely used correlations are documented below

1.5.1 The Sobocinski-Cornelius Method

Sobocinski and Cornelius (1965) developed a correlation for predicting water breakthrough time based on laboratory data and modeling results. The authors correlated the breakthrough time with two dimensionless parameters, the dimensionless cone height and the dimensionless breakthrough time. Those two dimensionless parameters are defined by the following expressions:

Dimensionless cone height Z

$Z = 0.492*10^{-4} (\rho_w - \rho_o)K_h h(h-h_p)/u_o B_o Q_o$

Dimensionless breakthrough time (tD)BT

$(t_D)_{BT} = 4Z + 1.75Z^2 - 0.75Z^3 / 7\text{-}2Z$

The authors proposed the following expression for predicting time to breakthrough from the calculated value of the dimensionless breakthrough time $(t_D)_{BT:}$

$t_{BT} = 20325 u_o h\Phi(t_D)_{BT} / (\rho_w - \rho_o) K_v (1+M^{\alpha})$

Joshi (1991) observed by examining Equation 22 that if Z is 3.5 or greater, there will be no water breakthrough. This observation can be imposed on Equation 9-21 with Z □3.5 to give an expression for calculating the critical oil flow rate:

$Q_{oc} = 0.141 * 10^{-4} (\rho_w - \rho_o)K_h h(h-h_p) / u_o B_o$

1.6 PARAMETERS OF CONING IN OIL WELLS

Though the mechanism of water coning is well known, its control is very limited, The reason is that only three out of seven coning variables can be controlled, To substantiate this statement, let us overview the known facts about water coning and its control. Parameters affecting water coning in vertical wells are: the mobility ratio, oil zone thickness, ratio of gravity forces to viscous forces, well spacing, ratio of horizontal permeability to vertical permeability, and well penetration and production rate, The first three variables are practicality beyond technical control, The mobility ratio effect on water coning was studied using scaled laboratory model, Studies with a radial model showed that mobility ratio inversely affects production performance, Also, the ratio of water mobilities, in the aquifer and water invaded zones, positively affects production performance, Studies with another three. dimensional model revealed that mobility ratio values greater than one engendered the worst coning effects, The higher the mobility ratio was, the faster the breakthrough occurred, The study showed that when the mobility ratio is greater than OF*, the water coning rises quickly and the water cut goes through a rapid increase, As production continued, the cone expanded In all directions and lowered oil production to within a few percent of its Initial value, When the mobility ratio was less than one, the water cone first expanded outwards radially, and then it gradually rose towards the well. The changes ln the water cut values were gradual and were spread over a longer period of production, The pay-zone thickness affects water coning in relation to the water zone size. Studies show that as the ratio of water to oil zone thickness increases, coning severity also increases while other parameters remain unchanged. Consequently, a serious coning problem might be expected at the end of oil production when most of the pay. zone has been invaded by water. The third coning variable is ratio of gravity force to viscous force, This ratio is a fundamental measure in the phenomenon because water coning occurs when viscous force, engendered by fluid movement, overcomes gravitational force Induced by the differences in fluid densities. In the laboratory experiments with the pie. shaped, radial model, the ratio of gravity to viscous force was calculated as:

$$R_{gv} = \frac{g \, \Delta p \, A \, k_h}{Q_o \, \mu_o} \qquad (1)$$

where,

R_{gv} = the ratio of gravity force to viscous, dimensionless
g = acceleration of gravity
Δp - density difference
A = model area
k_h = horizontal permeability
Q_o = oil production rate
μ_o = oil viscosity

Shown in Figure 5 is the increase in water cut caused by water coning during oil production, The results indicate the alleviation of water coning at high values of Rgv. The first variable which can be controlled is well spacing, Its effect on water coning is also shown in Figure 5, The figure clearly indicates that water coning can be dramatically reduced by drilling more wells at closer spacing. However, the economics of such control is highly questionable. The other potentially controllable variable is the ratio of vertical permeability to horizontal permeability, As evidenced in Figure 6, reduction of this ratio reduces coning.

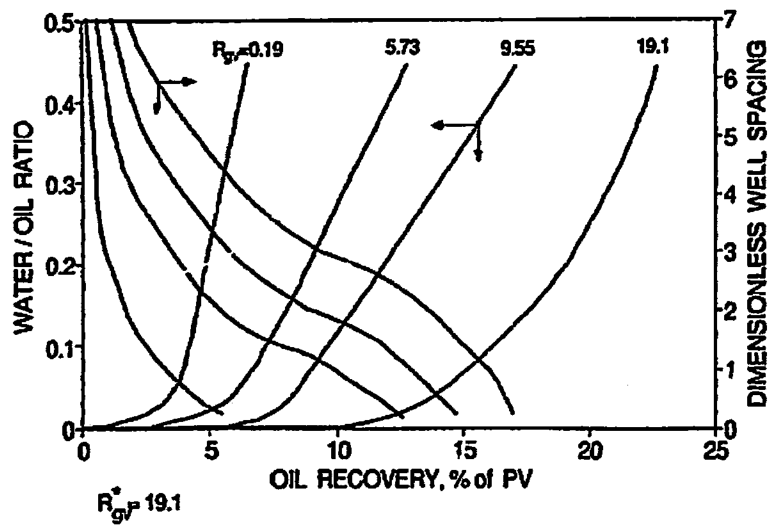


Figure 5: Effect of gravity /viscous forces ratio Rgv and well spacing on water coning

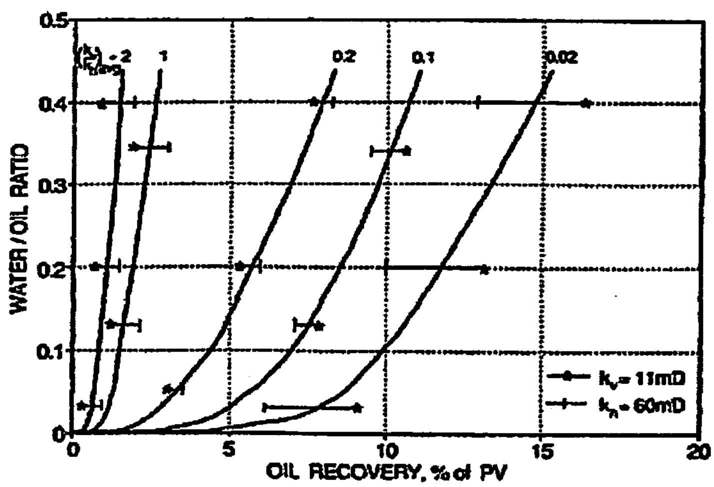


Figure 6: Effect of vertical to horizontal permeability on water coning

Such an effect was observed in the Middle East at a large oil reservoir, where a tar barrier ("tar mat") was present between oil and 'water zones, Technically, the permeability can be affected by fracturing formation, However, the sole increase of horizontal permeability through fracturing is not feasible because in deep well fracturing the improvement of vertical permeability is more likely to occur than that of horizontal permeability, Well penetration can be controlled through completion practices. Early studies using an electrical model to determine the effect of well penetration showed that coning would increase with increasing well penetration, in the scale model studies, a strong dependence of coning upon well penetration was evidenced as a relationship between the water breakthrough time and the fraction of the pay.zone penetrated by a well. When the well penetration reached 75% of oil zone thickness, the water breakthrough occurred almost instantaneously. To minimize coning, well penetration should be minimum. Such completion will certainly maximize oil recovery but will also minimize the well productivity. Theoretically, the well completion design under conditions of water coning may be viewed as an optimization problem, In field practice, however, the perforation Interval Is usually selected without significant technical considerations. Some recent studies show that horizontal completions in the top of an oil zone may prevent water coning, increase production rates and improve oil recovery Oil production rate Is easy to control. Its strong effect on coning has been proven in laboratory studies (Figure 7) and in oilfield practices (Figure 8), Shown in Figure 4 are the annual production plots for oil and water from a shallow oil bearing sand in the Lafitte field of Jefferson Parish, Louisiana.

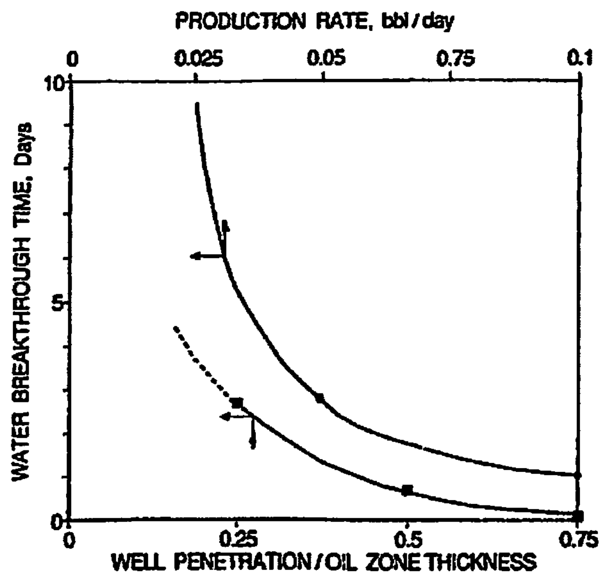


Figure 7: Effect of well penetration and oil production rate on water coning

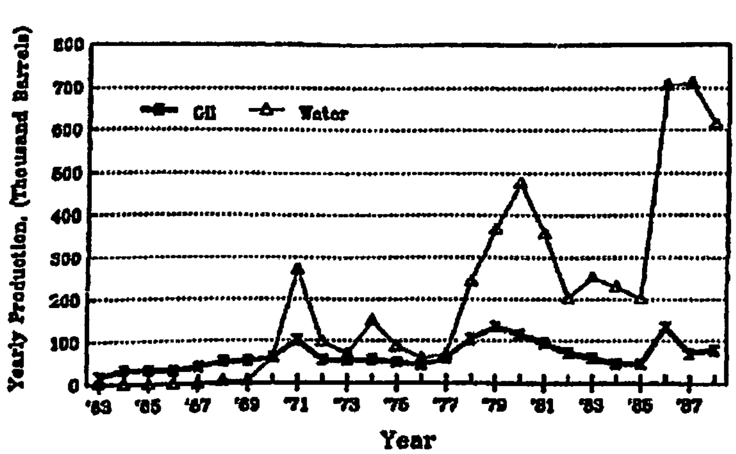


Figure 8: Yearly production of oil and water from north reservoir in Laffitte field of Jefferson Parish ,Louisiana.

A steady increase of water production results from water encroachment and coning mechanism, More characteristic, however, are the drastic changes of water production caused by relatively small changes In oil productions, It is evident from these plots that the two- to five-time increase of water production resulted from the two-time increase of oil production in 1971, 1979, and 1986.

Control of water coning requires reduction of the oil production rate to below the critical rate. Predictive models to calculate this rate have been recently reviewed. In many cases, however, it is not economical to keep the oil production rate below its critical value. Moreover, once the breakthrough occurs, it may be difficult to return to the initial low value of water cut, even at the reduced oil rate, due to the irreversible change of the mobility ratio caused by the imbibition/ drainage effects upon the relative permeability, The above analysis indicates that the theoretically available methods to control water coning have very limited practical applications, Hence, there is a need for innovations.

2. DOWN WATER SINK TECHNOLOGY

2.1 INTRODUCTION

Downhole water sink is a new technique for producing water-free hydrocarbons from reservoirs with bottom water drive and strong tendency to water coning. Conventional wells in these reservoirs produce increasing volumes of brine with decreasing amounts of oil or gas which ultimately leads to early shut downs of these wells without sufficient recovery of hydrocarbons in place. Furthermore, the produced waters are contaminated with hydrocarbons and require costly treatment prior to offshore discharges or subsurface injections.
DWS technology eliminates water cutting the hydrocarbon production by employing hydrodynamic mechanism of coning control in-situ at the oil-water or gas-water contact. The mechanism is based upon a localized drainage generated by a controlled downhole water sink installed in the aquifer beneath the oil or gas-water contact

2.2 HISTORICAL BACKGROUND

A DWS well completion is a developing technology for producing reservoirs with water coning problems. The DWS wells have two completions isolated by a packer; at the top of oil column – for oil production, and at/below OWC - for water drainage (water sink completion). The rate of water drainage is adjusted to the production rate so that the water cut at the top completion is greatly reduced or entirely eliminated. Moreover, the drained water may not be produced to surface but injected deeper in the same well into a disposal zone. Operational and design principles of DWS wells have been studied theoretically and experimentally since 1991. More recent studies focused on comparing DWS with conventional completions. The studies showed better performance of DWS wells in terms of water coning reversal and higher oil production rates. After successful first field implementation of DWS, in 1994, by Hunt Petroleum8, several other companies tested the technology in the field reporting good results. In 1997, a joint industry-LSU alliance, Down hole Water Sink Technology Initiative, was formed and has been working on research and DWS technology transfer ever since. Presently, two field projects of DWS are under development by the consortium members. To date, five field tests with DWS well completions have been performed. The results showed that DWS could control water coning and increase oil production rate. None of these tests, however, was long enough to show DWS potential to improve process of oil recovery comparing to conventional wells. The objective of this study was to examine the potential of DWS for improving oil recovery in terms of recovery factor and time in view of total production of liquids (oil and water) from reservoirs. Two research tools were used in this study, a physical Hele-Shaw model of the well-reservoir system, and numerical reservoir simulator. Two measures of well performance were considered for the comparison of DWS with conventional single completion: oil recovery, and withdrawal of water from the aquifer. (The criterion of water withdrawal seemed more appropriate because in DWS wells some water may not be produced to surface but re-injected into the same well below the withdrawal (drainage) depth.) It was realized that any improvement in one of the two measures would indicate a relative superiority of DWS over conventional completion, while an improvement in both measures would define a case for unconditional advantage of using the DWS instead of conventional completions.

The study was conducted through a series of laboratory or computer-simulated experiments. In each experiment, the production form the two completion systems would be mathematically simulated (or physically modeled), side-by side, for the same arbitrarily selected reservoir properties and the well completion geometry. The results provided an estimate of the advantage gained from using a better completion system in this reservoir.

To date, field trials of wells with DWS completions have shown that this new technology could control water coning and increase oil production rate. None of these tests, however, was long enough to show DWS potential to improve process of oil recovery comparing to conventional wells. Presented in this report are results from a recent project of the R&D consortium of nine companies at LSU – Down hole Water Sink Technology Initiative. The recovery study involved experiments with the physical model and computer simulation runs. The laboratory results showed that, for the same rate at the top completion, DWS dramatically accelerated the recovery process; A five-fold increase of the oil production rate was reached without changing the rate at the top completion - by adjusting the drainage rate at the bottom completion. The results also showed a 70-percent increase of oil recovery; from 0.521 up to 0.882 for conventional and DWS completions, respectively. The computer-simulated experiments with commercial reservoir simulator confirmed the thesis on better recovery with the DWS completions by showing a 30-percent increase of recovery factor from 0.61 to 0.79 for conventional and DWS completions, respectively. The results also gave a fivefold reduction of the time required to reach the limiting 0.98 value of water cut. However, accelerated recovery process with DWS required a substantial up to 3.5-fold increase of total water production. The simulation experiments clearly showed that the main advantage of using DWS is its flexibility of controlling the recovery process. For conventional completions, the recovery could be slightly increased by reducing production rates and largely increasing production times. For DWS, on the other hand, production process could be optimized for maximum recovery, minimum time, or minimum cumulative water produced by seeking a best combination of the top and bottom rates.

2.3 PRINCIPAL OF DOWN WATER SINK TECHNOLOGY

The well is dual completed so that the lower perforations are placed in the water zone, and water can be produced concurrently and independently to oil production, These two producing streams are separated by packer so that water does not mix with oil. Coning control is performed by adjusting water production rate to oil production rate in order to prevent the water cone from breaking through the oil into the oil perforations, Physically, the water sink (water perforations) alters the flow potential field around the well so that the water cone is suppressed, At eachpoint, the upwards vertical component of viscous force generated by the flow into the upper (oil) perforations Is reduced by the value of the downwards vertical component of the second viscous force generated by the flow into the water sink. At equilibrium, a stable water cone is "held down" around and below the oil-producing perforations.

There are several potential advantages of this method:

1, Oil production rate increase without water breakthrough;

2, Well life extends far beyond its value without coning control;

3. Oil recovery per well (and for the whole reservoir) increases due to the following mechanisms:

A Production can be continued with high levels of static OWC (caused by the bottom water drive invasion), even when this level reaches the oil perforations , and

B. Well productivity will be high because the near-well zone permeability to oil is not reduced by water encroachment,

4, Produced water will not be contaminated with crude oil, demulsifiers and other agents used in oil production. Therefore, it will more likely meet effluent discharge limitations imposed by the environmental regulations in the area,

5. The water/oil ratio will be reduced with the new method. The purpose of this study is to evaluate the coning control potential of this method, as well as to compare its performance to the conventional method of oil production under the conditions of bottom water drive. Mathematical simulation is used to predict the methods performance.

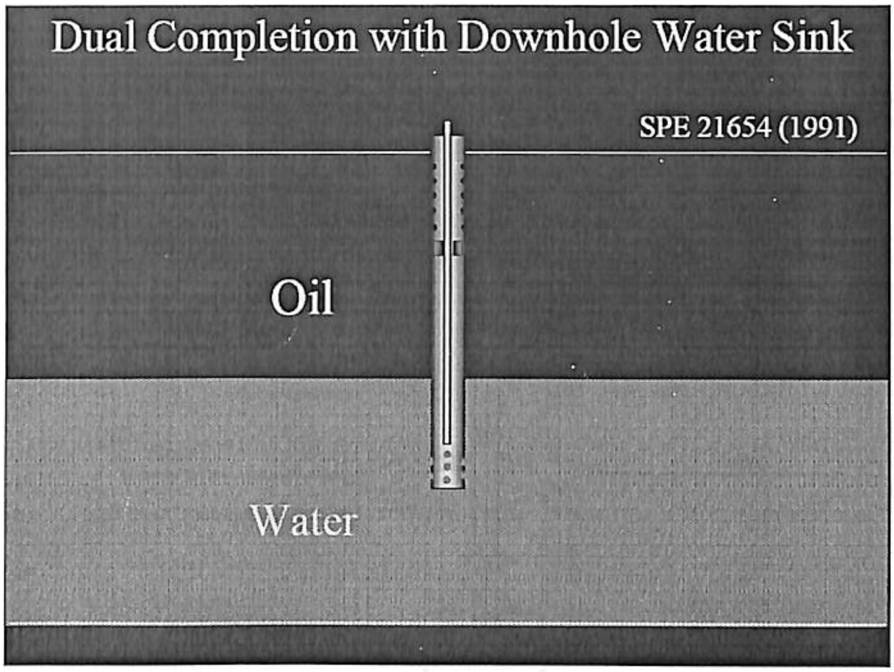


Figure 9: Dual completion with DWS.

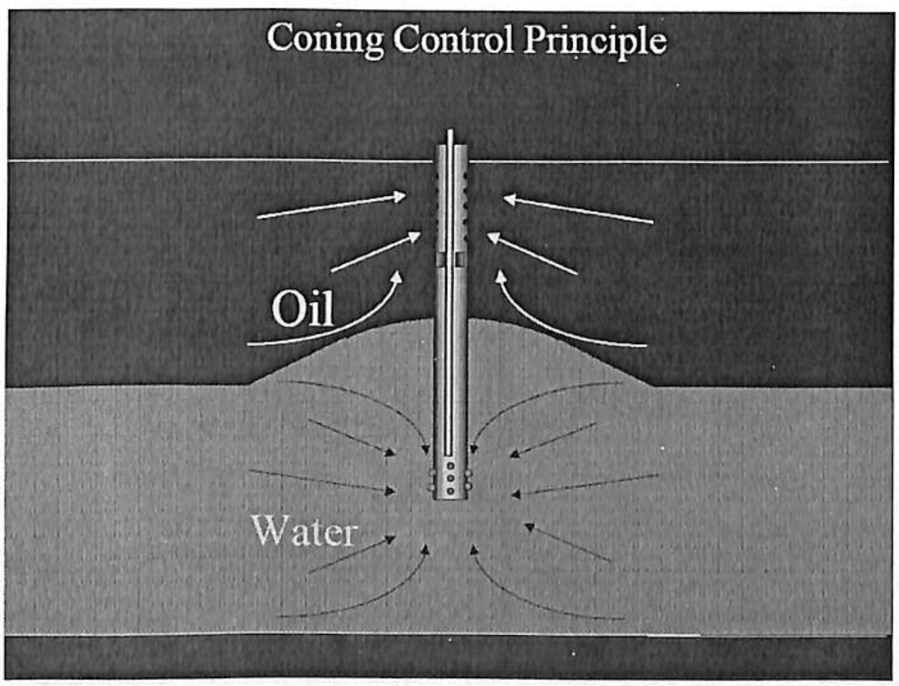


Figure 10: Principle of DWS.

2.4 Two down water sink arrangements:

DWS WATER DRAINAGE–INJECTION WELL

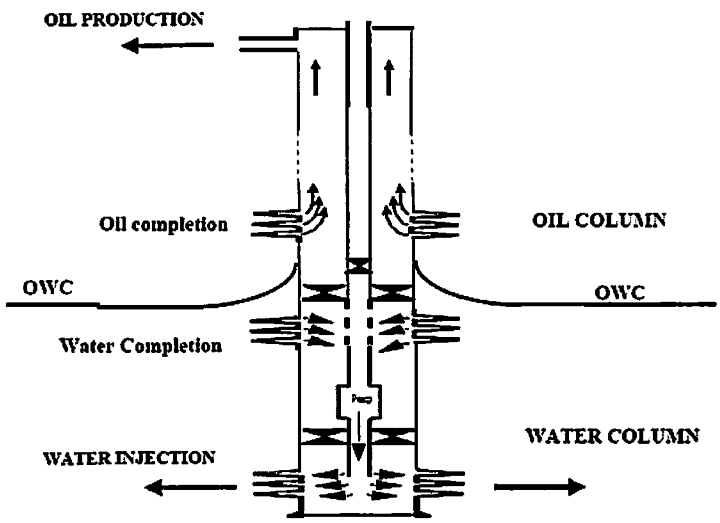


Figure 11: DWS water drainage-injection well arrangement.

DWS WATER DRAINAGE–PRODUCTION WELL

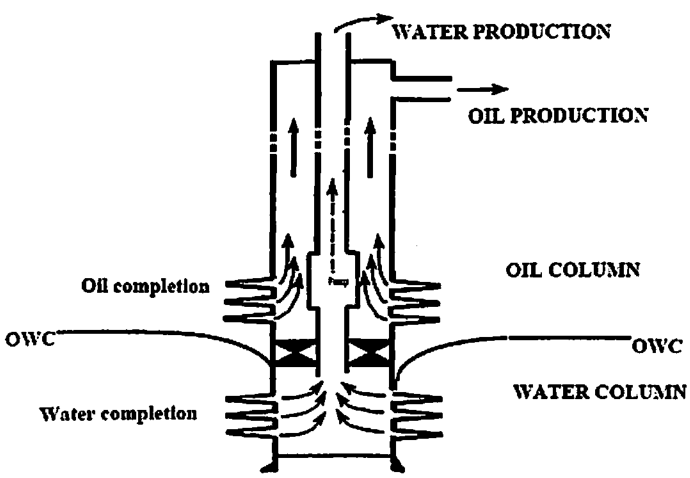


Figure 12: DWS water drainage-production well arrangement.

2.5 MECHANISM OF CONING CONTROL WITH WATER SINK

The objective of the first part of this study is to understand the mechanism and define the limitations of this new method. The first obvious question is what is the shape of the water cone that is induced by the water sink production at various values of water/oil ratio, two cases (low and high level of oil productions) were studied using the reservoir data from Table 1A.

Figure 13 shows the development of water cone profiles for varying water sink production rates sink at a constant oil rate of 300 bbl/day. The uppermost curve represents water coning without water sink. It is evident that breakthrough has occurred, In fact, the critical oil flow rate calculated from the new model for this case is 257 bbl/day, The deflection of the cone's surface represents the effect of the upper boundary, The two curves below (Qw=5% O., and Qw=10% O.) indicate a dramatic effect of small production at the water sink on the vertical extend of the water cone, The cone develops a circular and flat top surface (water table) with 20 ft in diameter, located approximately 30 ft below the oil perforations, Further increase of water production (Qw=50% Qo) lowers the water table so that the cone becomes a ring having 20 ft ID and 200 ft OD surrounding a relatively flat central water table with the well in its center, Both the ring height and the position of the water table are adversely affected by the water rate, When the water rate reaches 70 % of oil rate, the water table caves, and the oil breaks through the water into the lower perforations. The above analysis indicates the importance of two geometrical variations associated with the water cone profile, the water ring height and the height of the central water table, For higher oil rate (Qo=500 bbl/day), as shown in Figure 14, the water breakthrough occurs even with water sink production of 100 bbl/day (i.e. 20% Qo).

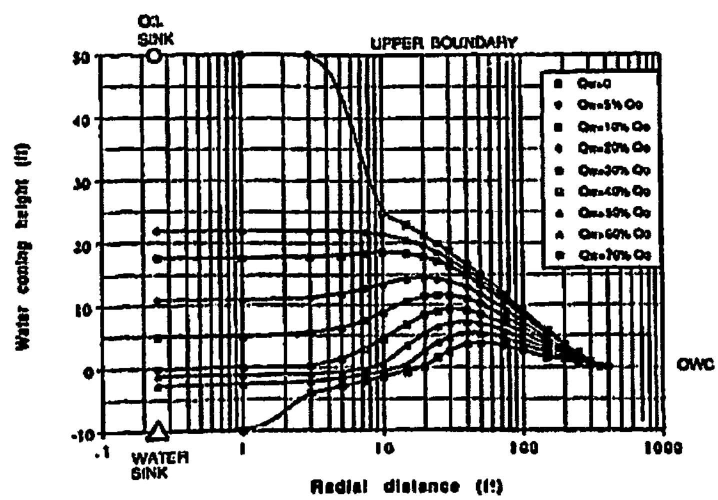


Figure 13: Water cone shape control with water production rate.

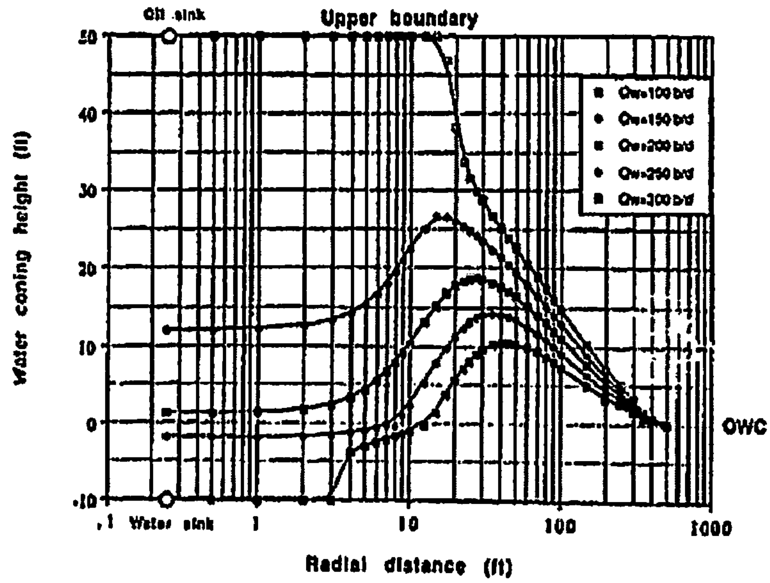


Figure 14: Breakthrough mechanism and principal of optimum cone control.

As expected, a higher water/oil ratio is required to begin the control of coning, and the most dramatic reduction of the water table takes place 'at Qw/Qo=25%, Nevertheless, the coning control is still feasible, and its mechanism is similar to the previously described, The size of the water ring is unaffected by higher oil rate, The most likely reason for this Is that the fraction of the water sink is unchanged. However, the height and shape of the water ring are affected by high oil rate. The water ring becomes taller, thus indicating that some limiting value of oil production can be expected. Such a value will build the water ring so tall that the oil perforation will be surrounded by a water "level", located 20 ft from and around the well. Therefore, it is postulated here that the conventional concept of critical oil production, with water breaking into the oil perforations, is not a good indication of the maximum limiting oil rate when the water sink control is used. To substantiate the above predicament, the conventional critical oil flow rates were calculated for the case and are shown in Figure 15 as a function of the water/oil production ratio, Qw/Qo, and water sink position, hw. The first observation is that, as intuitively expected, there is no theoretical limit for oil production with this method, except for the hydraulic performance of well completion. Such conclusion, however, is much too good to be true. Indeed, the actual maximum oil rate exists and can be derived from the stability required for the water ring, as illustrated in Figures 13, and further discussed in the next chapter. Another interesting observation from Figure 17 Is that the water breakthrough can be avoided with relatively low values of water/oil production ratio which tend to approach asymptotically the values ranging from 0.27 to 0.85, It means that for this method, values of water/oil production rate ratio smaller than one can be expected. The position of water sink (below the static OWC), hw, strongly affects the amount of produced water. As shown "in Figure 15, the upwards movement of static OWC above the water sink, i.e. increase of hw from 5 ft to 25 ft, will cause a three-time increase of water production at the same oil production rate,

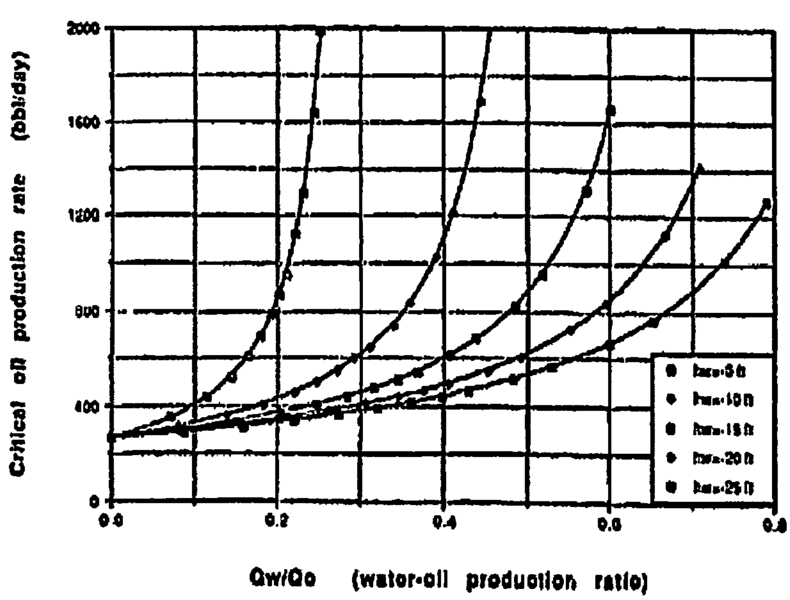


Figure 15: Critical oil rate Vs. water oil rate ratio and water sink depth.

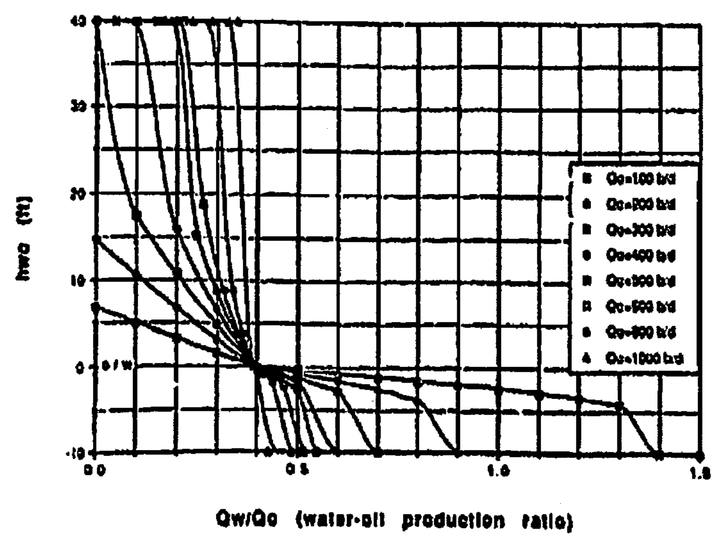


Figure 16: Sensitivity of hwo to water production at various levels of oil rates.

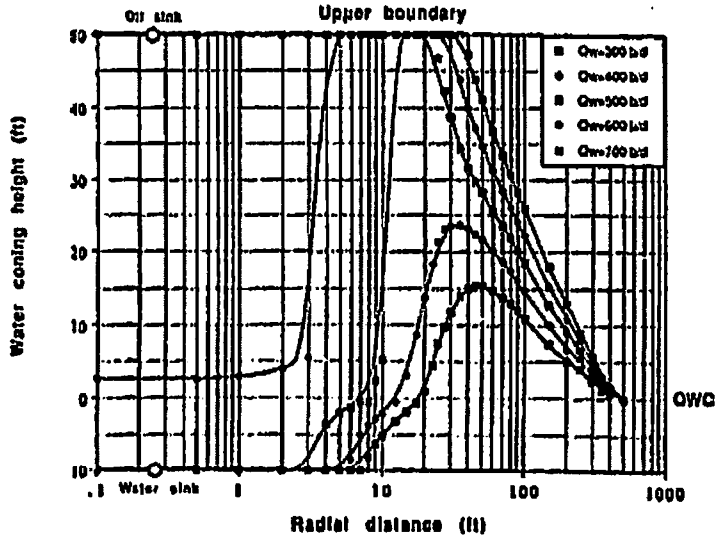


Figure 17: Water cone instability mechanism- excessive oil rate (1000bbl/d)

2.6 MAXIMUM OIL PRODUCTION RATE

As postulated above, water breakthrough was not a criterion for the maximum and limiting value of oil production rate when using water sink, Therefore, the next step of this research was to define some physical conditions which limit the oil production. The postulated criterion is the stability of the controlled water cone. It was learned from several simulated scenarios that the higher the oil production is, the more unstable the position of the controlled cone's water table, In other words, the position of water table becomes very sensitive to small changes of the water/oil

production rate. This observation is supported by the plots in Figure 17, which represent relations between water table position and water sink production rate for various rates of oil production, As can be seen, for the low oil production rate (100 bbf/day), the water table is stable and insensitive to water rates. When oil is produced at the rate of 1000 bbl/day and water sink produces 360 bbf/day, the controlled water table is 20 ft below the oil perforations. However, there is no stability in this control because a small drop in water production from 360bbf/day to 330bbl/day will cause an Instantaneous water breakthrough. Moreover, the casual increase of water production to 430 bbl/day will create a "lip-flop" condition in which the water cone will instantly reverse to the oil cone and the oil will break through into the water perforations. In addition to water table instability, water ring height is also an important indicator of water cone stability, As shown in Figure 18, when the oil is produced at 1000 bbl/day, no coning control is possible at ail. Not only is the water table prone to "flip. flopping", but also the water ring stands thin and tall, thus intercepting the flow of oil into the perforation, Moreover, further increase of water production from 500 to 600 bbl/day brings the top of the water ring down but simultaneously causes oil breakthrough into the water sink. Therefore, the design of the water cone control operation should consider both the water table sensitivity to water sink production and the height of the water ring.

3. MATHEMATICAL MODEL OF WATER SINK

The model assumes that when at any fixed production rate or bottom hole pressure, with the water lying statically at the lower boundary of the oil zone, the pressures at the water-oil interface p(r,z) will satisfy the equation

$$p_{(r,z)} + \gamma_w\, g(h - z) = p_{(r,z)} + wgy = p_b \qquad (2)$$

where pb is the formation pressure as measured at the bottom of the oil zone at a point remote from the well, and gama w is the density of water.

These assumptions, based on Muskat's theory, stem from the reasons that water, being of greater density than the oil, will, under static conditions, remain at the bottom of oil producing section, Therefore, its rise, as shown in Figure 18, represents a dynamic effect in which the upward-directed pressure gradients associated with the oil flow are able to balance the hydrostatic head of the elevated water column,

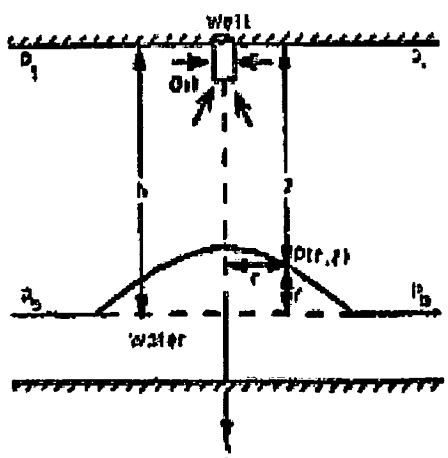


Figure 18: Water coning coordinates and symbols

When the perforated sections of a well are short, their productions can be approximately treated as point sources. In this case, the spherical solution of the flow potential is a good approximation. The one dimensional equation of the flow potential in spherical coordinates is:

$$\frac{\partial^2\Phi}{\partial r^2} + \frac{2}{r}\frac{\partial\Phi}{\partial r} = \frac{\Phi\mu c}{k}\frac{\partial\Phi}{\partial t} \qquad (3)$$

To solve this differential equation, the following dimensionless parameters are defined:

$$r_D = r / r_w \tag{4a}$$

$$t_D = \frac{kt}{\Phi \mu c r_w^{2}} \tag{4b}$$

$$\Phi_D = \frac{4\pi k r_w}{Q_o \mu} (\Phi_1 - \Phi) \tag{4c}$$

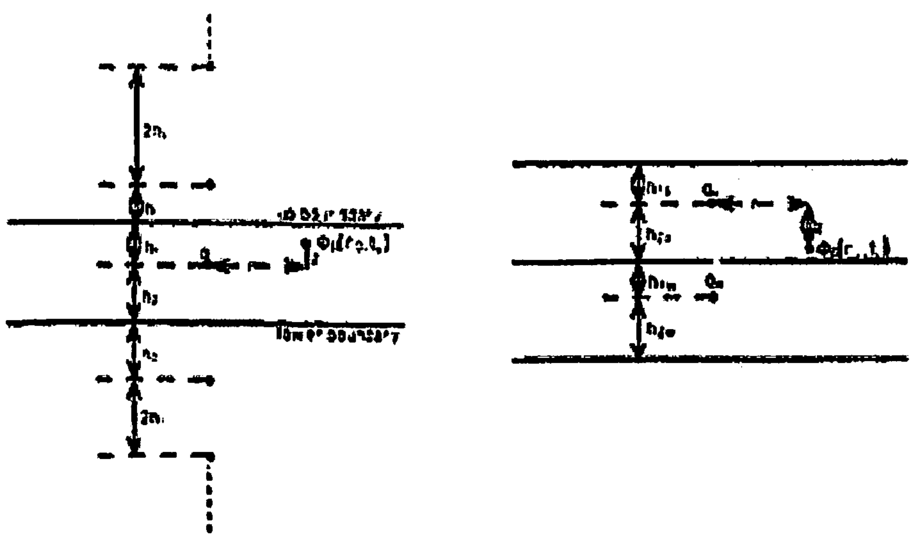
For steady state conditions, the flow potential is:

$$\Phi_D(r_D, t_D) = \frac{r_{De} - r_D}{r_{De}\, r_D} \tag{5}$$

The method of images can extend the above solutions to the finite thickness reservoir, Figure 19A shows the method of images applied to a single zone. For this case, the steady-state flow potential is expressed as:

$$\Phi_D(r_D, t_D) = \frac{r_{De} - r_D}{r_{De}\, r_D} + \sum_{i=1} \sum_{j=1} \frac{r_{De} - r_D}{r_{De}\, r_D} \tag{6}$$

Calculation of the flow potential distribution for a single zone using Equation (6) is straightforward, For the double zone system of oil underlain by water, and with two production sinks, the flow potential at a point of interest is superimposed from both sinks.



A B

Figure 19:Flow potential distribution model using method of image.

A- single zone with one sink.

B-dual zone system with two sinks.

The nomenclature for this case is shown in Figure 19B. The calculation procedure includes two basic steps:

1. Check whether the coning liquid is oil or water by separately calculating the flow potential at OWC if reduced by each sink.
2. Calculate the coning profile using superposition of Equation (6) and the iteration procedures until Equation (2) is satisfied, The effect of vertical and horizontal permeability Is implied in the definition of spherical permeability is used in the model as:

$$k = \frac{3k_h k_v}{k_h + k_v} \qquad (7)$$

3.1 MODEL VERIFICATION

A literature search has been made to select water coning models to be used for comparison with this simulation method. Because the method does not simulate coning after the breakthrough occurs, the verification was limited to the comparisons of critical rates and coning profiles, It was also realized that a comparison can only be made for the oil producing perforations (the water sink flowrate is zero) because the conventional models do not consider the water. producing perforations. Muskat presented a simple analytical model of water coning in a homogeneous system with a constant mobility ratio and an iso potential at initial owc, Muskat's analytical model, together with his graphical method, predicted the equilibrium conditions of water cone. The critical flow rate was correlated with the well penetration for various oil zone thicknesses. Schols developed an empirical formula using a Hele-Show model to calculate the critical oil production rate. Meyer and, Gardner presented a radial flow of oil under its own hydrostatic head. both Schols' and Meyer. Gardner's methods provided the formulas for critical oil flow rate as a function of density differential, well penetration, oil zone thickness, oil viscosity and permeability, and the size of drainage area.

Wheatly simulated oil/water coning using an approximate analytical model. The assumptions made in his model are: (1) oil partially flows into the well in the presence of underlying water; (2) the reservoir is taken to be homogeneous and bounded above by a horizontal impermeable barrier extending to a distance (drainage radius) from the well; (3) the region for flow is bounded below by the oil water contact, which is deformed upwards near the well in response to the reduced pressure; (4) the influx of oil at the drainage radius is assumed to be steady and radially symmetric; (5) the underlying water is stationary and entirely segregated from the oil; and (6) the fluids (oil and water) are considered to be incompressible, Based on these assumptions, Wheatly developed a modified flow potential equation and an Iterative procedure to calculate critical flowrate, Soboclnskl and Cornellnsl developed correlations for predicting the behavior of a water cone as it builds from the static water-oil contact to breakthrough, They noted that the previous analyses of critical production rate disregarded the effect of time required for a cone to build up just before its breakthrough, They believed that initially a well could be produced at rates above the critical rate until the cone reached its critical height, They also looked at two parameters defined as dimensionless cone height and dimensionless time, The data for their study was obtained by using a laboratory, sand packed model and a computer program for two-dimensional, two-phase, Incompressible fluid flow. A correlation of dimensionless cone height versus dimensionless time was made based on the results from the physical model, computer program and dimensional analysis. Welge applied a numerical method, the alternating direction Implicit procedure (ADIP), to simulate the water coning behavior. The ADIP method was used to solve the diffusivity equation for two-phase flow in a two-dimensional grid system. Several improvements were made to increase precision of the saturation computations near the wellbore. The calculation results were verified using the laboratory measurement data of Sotmclnski et al. as well as several case histories. The coning model developed in this research was verified using predicted values of the critical oil production rate for a reservoir having the properties shown in Table 1A.

Table 1: Reservoir Data For Calculation Example

	Table 1-A	Table 1-B
Formation Thickness (ft)	100	120
Oil zone thickness (ft)	50	70
Oil perforation position	Top of oil zone	0-50 ft from the top
Horizontal permeability (md)	1000	236
Vertical permeability (md)	500	125
Oil viscoty (cp)	1	2 4
Oil density	0 7	0 812
Water density	1	1 15
Wellbore radius (ft)	0 25	0 25
Reservoir radius (ft)	500	1300

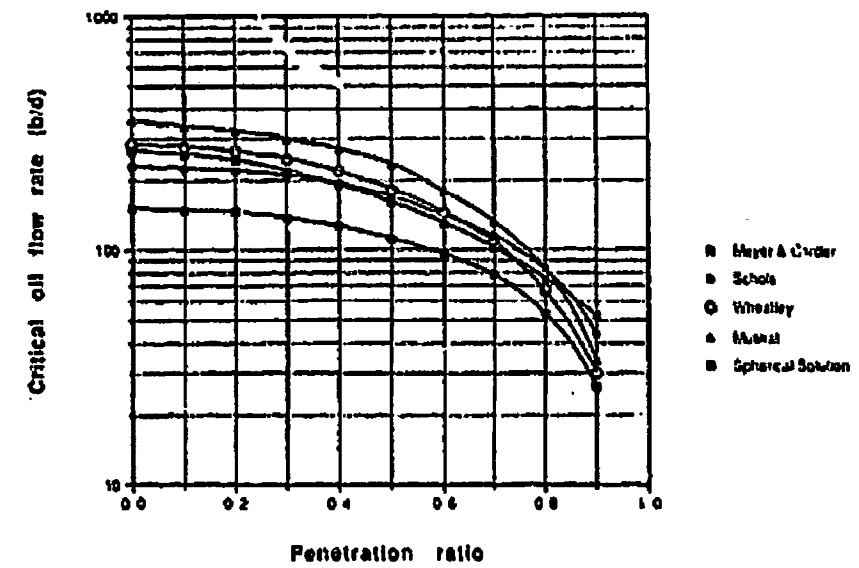


Figure 20: Verification with other models using critical production rate

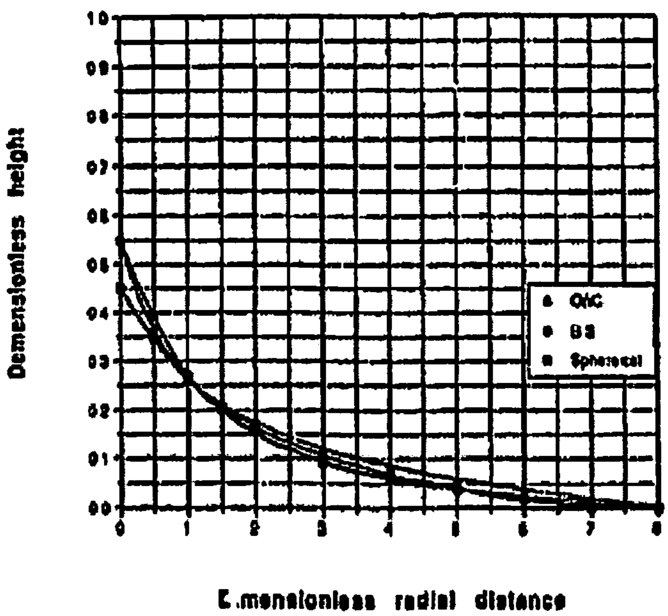


Figure 21: Verification with other models using coning profile

The critical oil flow rates were calculated for different penetration ratios, The results are shown in Figure 20 together with the critical oil flow rates calculated from other methods. The plots show that the critical oil flow rates calculated from this model match Wheatley's critical oil flow rates. The critical oil flow rates calculated by Muskat's method are higher and those calculated by Meyer and Garder's method are lower than the values predicted by this model. Also, as might be expected intuitively, the model does not work. well for well penetration values greater than 0,8 because it disregards the perforation length (note that the point sink is assumed to be located in the middle point of perforations). Figure 21 gives a comparison of the calculated water coning profiles. In this figure, the OWC profile is the water coning profile calculated using the Oil-Water Contact equation, and the BS. profile is the water coning profile calculated from the Bounding Streamline equation. The spherical profile is the water coning profile calculated by the method from this research, the comparison shows a good match between the water coning profile by this method and those calculated by other methods.

Recovery of oil from a reservoir with water drive depends on the efficiency of oil displacement by water. The volume of the reservoir invaded by water is mainly a function of resistance to fluid flow in different parts of the reservoir. Reservoir simulation studies and experiments on scaled models have shown that for a given reservoir geometry and properties, there is a unique relationship between water cut and efficiency of oil recovery. Moreover, Henley, Owens, and Craig noticed that the relationship between the reciprocal of sweep efficiency and WOR was linear for: $2<WOR<20$, and proposed a simple correlation based on this observation. Two coefficients used in the correlation were taken from a special set of graphs. Base upon these observations, we postulated that DWS could significantly improve oil recovery by reducing WOR in the production stream from the top completion in the oil column.

To study the effect of DWS on oil recovery, a special set of experiments was performed using a physical model of DWS described elsewhere. The study simulated oil production from a bounded oil reservoir overlying an infinite aquifer. In the study, the float switch controlling the WOC position (during the steady-state experiments) at the "reservoir end" of the model was disconnected. Thus, the supply of additional oil from the storage container was closed. At the same time, the solenoid valve controlling the supply of the water remained open. At the "well end" of the model, the production rates from the simulated top and bottom completions were measured with the fractional collector by sampling the two outlet streams pumped out of the model. Three top openings were used as a top completion and one bottom opening as a bottom completion. The experiments were performed at five different combinations (cases) of constant production rates at the top and bottom completions. Table 2 presents the results for the five cases. During the simulated production, motion of oil and water inside the Hele-Shaw cell was videotaped. Each experimental production run was terminated when oil cut measured in the sampling tubes became practically undetectable.

Shown in Fig. 22 and Fig. 23 are the plots of cumulative volume of oil produced vs. production time. The results clearly demonstrate strong dependence of cumulative oil production (i.e. oil recovery) upon the combination of the DWS well production rates. Also demonstrated in these figures is a fivefold recovery rate increase with DWS as compared to the conventional single completion.

Table 2: Oil recovery study with physical model.

Production schedule	Top pefs. rate, cc/min	Bottom perfs. rate, cc/min	Np, cc	Wp, cc	Np/N
Case 1	11.36	0.00	234.6	1843.0	0.521
Case 2	12.41	12.43	345.4	969.7	0.768
Case 3	12.13	30.00	362.0	1287.0	0.804
Case 4	7.63	37.30	343.1	1695.3	0.762
Case 5	11.76	57.72	396.8	1392.2	0.882

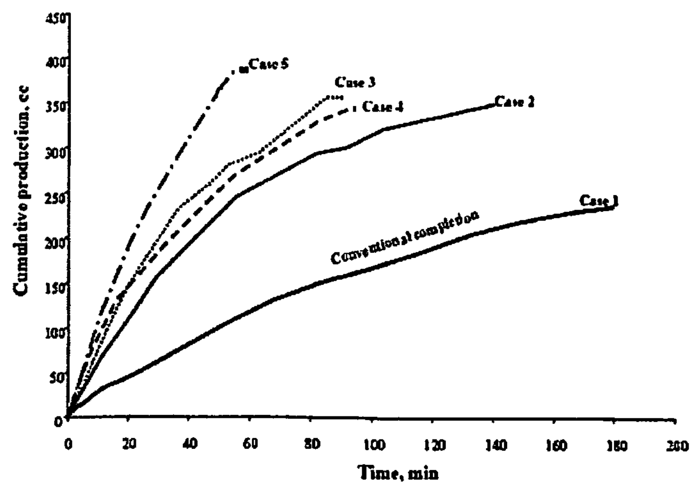


Figure 22: Increase in oil recovery by DWS is five fold.

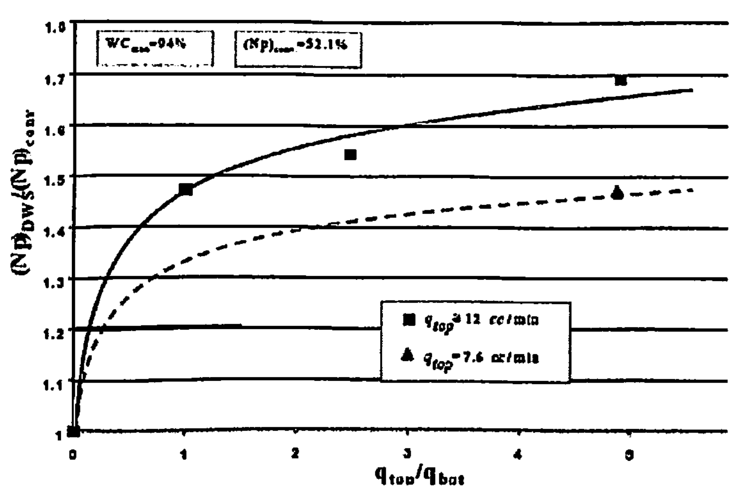


Figure 23: Optimum DWS well production schedule gives maximum recovery.

The experimental results show that DWS produced more oil in a shorter time. There was a 70 percent increase of oil recovery, from 0.521 up to 0.882, for the conventional and DWS completions, respectively. As expected, the highest value of oil recovery corresponded to DWS design with reversed coning, i.e., a maximum possible drainage rate at the bottom completion of the water sink. Figure 23 shows the effect of the drainage rate at the bottom completion on the oil recovery. For the water drainage rate five times greater than the production rate at the top completion, a 70-percent increase in oil recovery was observed. In contrast, as it is known from the water coning theory, a change of production rate in conventional completion does not result in variations of ultimate recovery. The study also revealed that certain values of the top-to bottom rate ratios may maximize recovery, thus indicating a need for optimized combinations of these two rates. Moreover, for the same rate at the top completion, DWS dramatically accelerated the recovery process: A five-fold increase of the oil production rate was reached – without changing the rate at the top completion - by adjusting the drainage rate at the bottom completion.

The computer-simulated experiments enabled us to model a broader range of real reservoir conditions with and without DWS. To simulate the process of recovery in a reservoir with water coning, we considered constant-pressure oil pay of finite size with bottom water influx. A volumetric two-dimensional radial (r-z) simulation model with a bottom aquifer was used. The effect of material balance was considered in the simulation model so that the horizontal oil-water interface was allowed to rise during the production process, while reservoir pressure was kept constant at all times. For a constant rate of well production, the system would stabilize at a steady-state flow conditions with two-phase flow (oil and water) and a constant value of solution gas. The reservoir data is given in Table 3. In the experiments, each run of simulated production history would be terminated using one of the two recovery time criteria: a 98 - percent water cut limit at the top completion, or a 99 - percent total water cut limit from both completions combined. Top completion water cut time limit. Experiments with the 98 - percent water cut limit at the top are summarized in Table 4. The notation is as follows: C100: conventional completion with constant production rate, 100 BFPD; D100 – 100: DWS completion with the top completion rate, 100 BFPD, and the bottom completion rate,100 BFPD; r1 through r23: index of simulation runs. The study showed that the DWS recovery process is different in many ways from that for conventional wells. In the DWS well, water drainage at the bottom completion keeps water/oil interface below the top perforations, which considerably delays water production from the top completion. The plot in Fig. 24 gives the top production water cut histories for different bottom drainage rates and a constant top rate of 100 stb/day. It becomes evident from the plot that draining water at the bottom completion would stimulate oil production at the top completion.

Moreover, shown in Fig. 25 is a recovery plot using the data from Fig. 24. The highest recovery in the shortest time was obtained for the DWS well production schedule with the highest water drainage rate. It becomes evident that the water drainage process opens the top completion to oil inflow so the recovery is increased and the recovery time shortened.

Table 3: Reservoir data used in the study with reservoir simulator.

Parameter	Value	Units
Top of the oil column	4760	ft
Top of the oil completion	4760	ft
Length of the oil completion	3	ft
Reservoir temperature	150	°F
Reservoir pressure	1788	psig
Initial depth of WOC	4770	ft
Top of the water completion	4780	ft
Length of the water completion	10	ft
Bottom of the water column	4830	ft
Horizontal permeability in oil column	1000	mD
Vertical permeability in oil column	900	mD
Horizontal permeability in water column	1000	mD
Vertical permeability in water column	900	mD
Water density	61.47	lb/ft^3
Water viscosity	0.46	cp
Oil API gravity	32.4	°API
Oil viscosity, corrected	1.25	cP
Oil Formation Volume Factor	1.26	bbl/STB
Residual oil saturation	15	%
Porosity in oil column	30	%
Porosity in watre column	37	%
Reservoir radius	300	ft
Capillary pressure	ignored	psig

The analysis of numerical experiments included a comparison of the DWS well recovery performance with conventional completions using the well production life limits set by the maximum values of a water cut at the top completion (0.98). A plot of the recovery factor for various constant-rate production schedules is shown in Fig.26. For conventional completion, increasing production rates from 100 stb/day to 400 stb/day reduced the recovery factor from 66% to 61%. However, applying DWS with the same 400 stb/day rate of production (Case D:200-200) gives a 73-percent recovery, which is 12% more than the C400 case Moreover, the increase of the bottom drainage rate to 1000 BFPD resulted in the recovery factor value of 79.3%.

Table 4: Summary of numerical methods.

Case Name	Simulatin run ID	Total rate stb/day	Production Time days	years	Recovery, fraction	Top Oil, Cum., bbl	Bottom Oil Cum.. bbl	Top WC %	Bottom WC %	Top Water Cum., bbl	Bottom Water Cum., bbl	Cum. Water bbl
C 100	r2	100	12190	33.4	0.66	70825	0	98.0%	N/A	1148215	0	1148215
C 200	r3	200	6293	17.2	0.61	65812	0	98.0%	N/A	1192748	0	1192748
C 400	r4	400	3618	9.9	0.61	65639	0	98.0%	N/A	1381401	0	1381401
D 100 - 100	r6	200	11248	30.8	0.72	78185	0	98.0%	100.0%	1046615	1124800	2171415
D 100 - 200	r7	300	9492	26.0	0.76	81722	0	98.0%	100.0%	867442	1903040	2770482
D 100 - 300	r8	400	8527	23.4	0.78	84563	0	98.0%	100.0%	768157	2562720	3330877
D 200 - 200	r9	400	6080	16.7	0.73	78331	0	98.0%	100.0%	1137669	1216000	2353669
D 200 - 600	r10	800	4195	11.5	0.79	84808	0	98.0%	100.0%	754232	2517120	3271352
D 100 - 2000	r11	2100	2204	6.0	0.81	83779	3883	98.0%	100.0%	136621	4404117	4540738
D 100 - 1000	r12	1100	3543	9.7	0.80	86410	0	98.0%	100.0%	267912	3543222	3811134
D 200 - 1000	r13	1200	2858	7.8	0.79	85549	0	98.0%	100.0%	485971	2857600	3343571
D 100- 700	r23	800	4569	12.5	0.79	85660	0	98.0%	100.0%	370340	3192000	3562340
C400	r41	400	5852	16.0	0.73	78256	0	99.0%	N/A	2262544	0	2262544

The mechanism of improved recovery with DWS completion stems from the shape of the oil water interface. For conventional single completions water cones are much taller than those for DWS completions. In the result, more oil becomes by-passed which reduces the recovery.

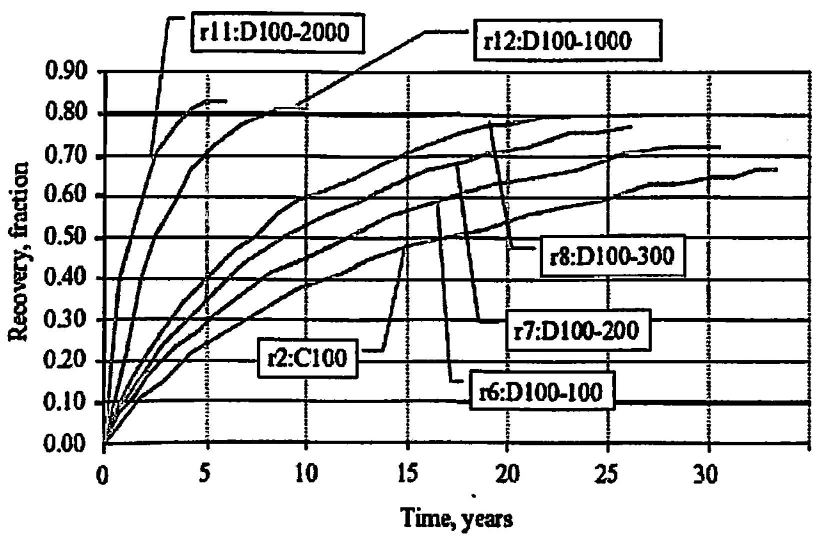


Figure 24: Oil increase at highest possible DWS bottom water drainage rate.

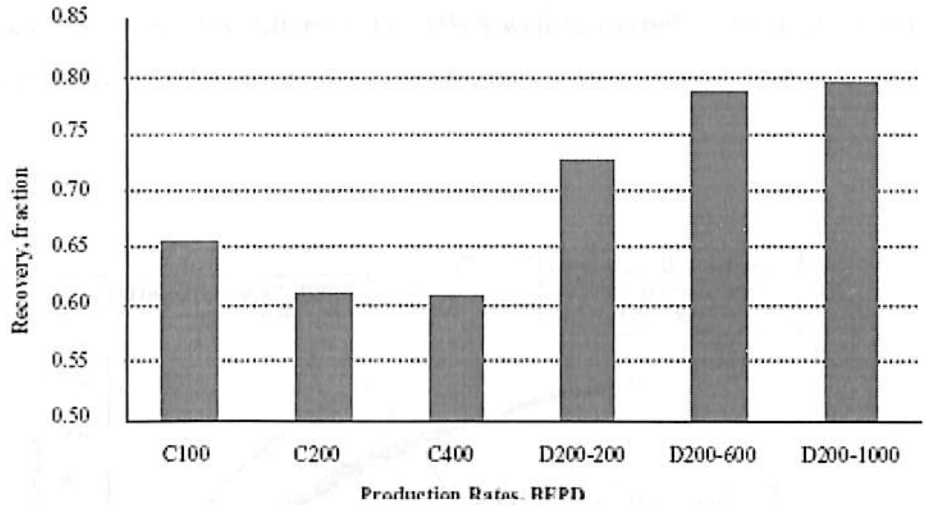


Figure 25: Recovery factor for conventional and DWS well.

3.2 TOTAL WATER CUT TIME LIMIT

The study with a total-water-cut production time limit was undertaken to make a completely unbiased comparison of DWS with conventional completions. The economic time limit of 98% water cut at the top completion may be considered a fair comparison because the conventional case simulation runs were terminated at 98% total water cut, whereas the DWS runs were stopped with total water cut reaching values from 99% up to 99.9%. (Prior to reaching the 98% water cut value at top completion the DWS well would continue producing above 98% total water cut because the bottom completion was producing 100% water so the total water cut was higher than 98%.) In this study, a total water cut limit was used and three cases were simulated, as follows: Cases r4 and r41 - A conventional well producing up to the economic limits of 98% and 99% water cut (Case r4:C400, 98% WC; and, Case r41:C400, 99% WC); Cases r8 and r9 - A DWS well having total liquid production rate equal to that for conventional well in Cases r4, and r41, and producing up to the economic limit of 99% total water cut (r8:D100-300, and r8:D100-300); Case r23 - A DWS well with high water drainage rate producing up to the economic limit of 98% total water cut (r23:D200-700). The recovery process for all above cases is presented in Fig. 6. The results showed that when the comparison was based on the total water cut limit with equal fluid production rates, the two production systems performed the same. The conventional case simulation run (r41) recovered 72.5% in 16 years, while the DWS case runs recovered 72.5% in 17.1 years (r8) or 73.6 % in 16.7 years (r9). However, for DWS well with high water drainage (Case r23:D100-700) was compared with conventional case of 400 stb/day (Case r41: C400) the result was drastically different. The DWS well recovered 73.1% in 8.74 years, which gave a 50 percent reduction of the recovery time for the conventional completion.

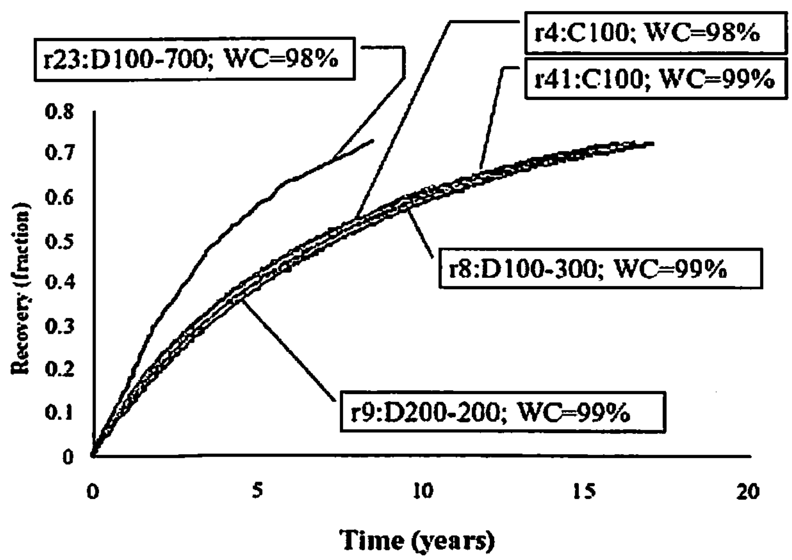


Figure 26: Recovery comparison for DWS and conventional completions.

DWS should not be evaluated under conditions of equal fluids production rates. The reason is that DWS has two completions and two isolated flow conduits, which means that there are two wells in one. Thus, DWS is capable of producing at roughly twofold the rate of a conventional completion. Also, DWS wells produce at smaller pressure drawdown in the oil column because the produced fluid is mostly oil with no or little of water. The results of numerical experiments support the thesis of better recovery with the DWS completions by showing a 30- percent increase of recovery factor: from 0.61 – for conventional completion, to 0.79 – for DWS completion. The results also showed a fivefold reduction of the time required to reach the limiting 0.98 value of water cut. Another insight from this study is the 20-percent improvement in recovery with DWS when the two completions were produced at the same total rate of fluids: 0.61 in 9.9 years and 0.73 in 16.7 years, for conventional and DWS completions, respectively.

Interestingly, it would take 48 years for conventional completion to reach 0.67 recovery, which is still smaller than the value of 0.73. The simulation experiments clearly show the advantage of using DWS due its flexibility in controlling the recovery process. For conventional completions, the recovery could be slightly increased by reducing production rates and greatly increasing production times. For DWS, on the other hand, production process could be optimized for maximum recovery, minimum time, or minimum cumulative water produced by seeking the best combination of the top production and bottom water drainage rates.

3.3 WATER WITHDRAWAL WITH DWS WELLS

The question of whether or not DWS could reduce water production cannot be answered without considering the oil recovery process. Water driven reservoir systems work similarly to water flood projects where the recovery factor and recovery time both depend upon the volume of water sweeping the oil zone. By this analogy, the more water was moved through the system the better the recovery and the shorter the time should be. Moreover, in the DWS wells the water drained at the bottom completion could be re-injected down hole in the same well so the actual water produced to surface would be a very small fraction of the total water withdrawal. Thus, for the purpose of clarity, we define the total water cut as a ratio of total water withdrawn to total liquids withdrawn from the reservoir-aquifer system. Clearly, this definition is consistent with the terminology used throughout the whole report. A recent analysis of DWS field tests showed that DWS could dramatically reduce water cut at the upper completion, thus making the completion open to production of oil. On the other hand, no improvement in reducing the total water cut was observed. Also, physical experiments revealed that the mechanism of water cut reduction results from the water cone reversal process.6 The experiments showed that the water cone reversal process could restore oil productivity in wells that have been completely "watered out." It was also observed that the cone reversal process would take much longer than the time for initial water breakthrough. One of the most frequently asked questions related to the DWS applications is whether the new technology would reduces the total water cut. Thus, the remaining part addresses the issue of water withdrawal and production by DWS wells.

4. EXPERIMENTS

4.1 PHYSICAL EXPERIMENTS

Presented in Fig. 27 is the recorded production history in a physical experiment performed on the Hele-Shaw model simulating a well producing at high production rate. For the first six minutes, the model was produced as a conventional well having a single top completion. During this stage of production, the average value of WC was 0.31. After 6.5 minutes the pump at the bottom completion was turned on. As a result of the water drainage, the water cone started reversing, which was demonstrated by declining values of WC in the fluid produced from the top completion. However, the value of total water cut initially increased after water drainage began. This increase was due to the additional production of water through the bottom completion. After reaching maximum, the total water cut started declining as a result of the cone suppression. After additional 4.5 minutes of water drainage, WC at the top completion dropped to zero and total water cut continued to decline. Finally, when the oil breakthrough occurred at the bottom completion, total water cut stabilized at the value of 0.25, which was 6% lower than its initial value for the conventional completion before activation of DWS. Since the water cut values fluctuated in time, this 6-percent reduction could not be considered significant. Thus, we concluded that DWS could not reduce total water cut in this experiment. Moreover, the plot of average WC in Fig. 27 indicates that DWS well would tend to withdraw slightly more water from the aquifer than a conventional well.

The experimental results, above, pertain to high rates of production and should be analyzed in the context of our previous experiments conducted over broad range of production rates. In these experiments, total water cut was measured for several combinations of the top and bottom completion rates. It was observed that the reduction of total water cut with DWS depends on the value of production rate in relation to ultimate rate. (Ultimate rate is the minimum rate of production in conventional completion, at which reservoir geometry becomes a restriction factor for the WC value, i.e. above this rate WC is maximum and independent for production rate.) For small production rates, below the ultimate rate, total water cut could be minimized with DWS. However, for high production rates, DWS would give total water cut equal to or even greater than that for conventional completions. A plot in Fig. 8 demonstrates these observations. The results show that a 38-percent reduction of total water cut is possible with DWS for an optimum combination of the top and bottom completion rates. However, as those rates are small, so they might be not economically feasible – subject to the DWS production optimization design. In view of these findings the tendency of DWS wells to increase cumulative withdrawal of water from the reservoir-aquifer system, demonstrated in Fig. 26 becomes simply a result of the high rate of production.

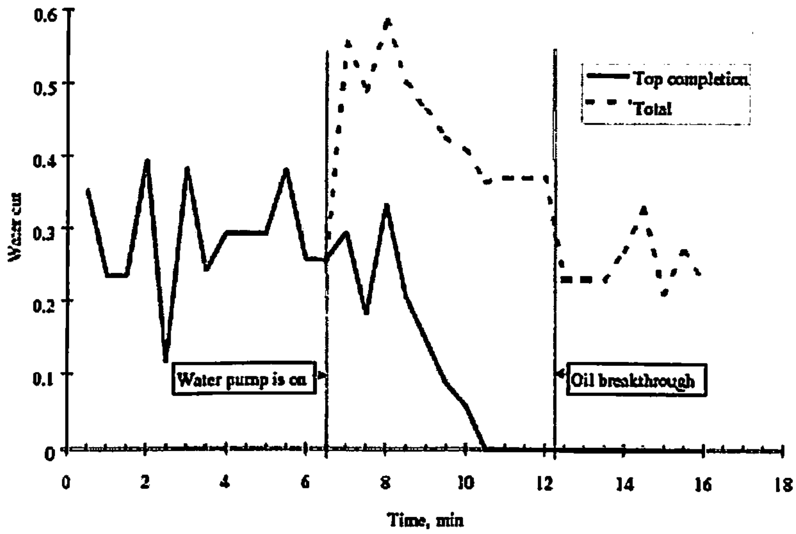


Figure 27: Experimental well production history show no reduction of water cut with DWS.

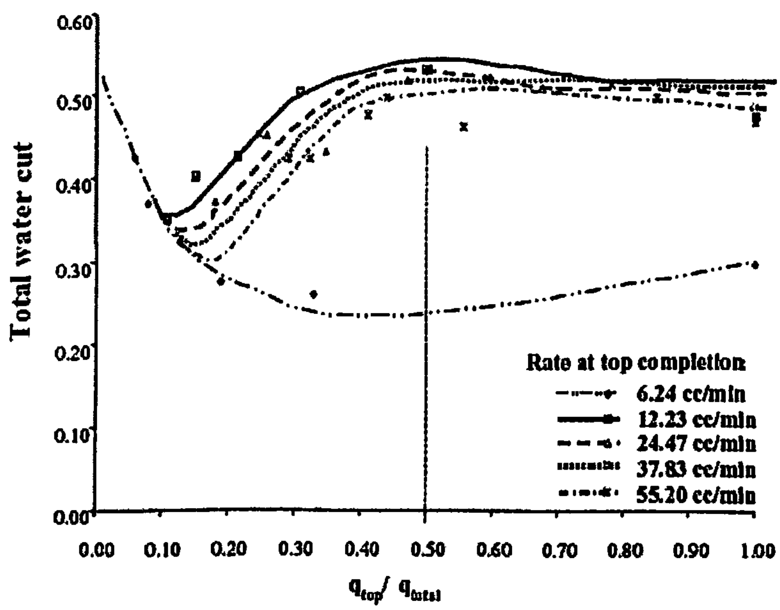


Figure 28: DWS minimizes total water rate at below ultimate rate.

4.2 NUMERICAL EXPERIMENTS

Examination of the simulation results summarized in Table 3 reveals that DWS produces more cumulative water than conventional completion while increasing oil recovery and reducing time of production. The mechanism underlying this result is the development of total water cut. As shown in Fig. 29 DWS gives higher total water cut than conventional completion during the initial stage of the recovery process (maximum increase of water cut at 0.2 recovery is 7%). This happens because DWS wells produce water form day one while conventional wells give initially water-free production. (This observation has an interesting implication with the DWS production schedules – delaying initial water drainage might reduce total water cut). However, as recovery increases, the total water cut values converge rapidly for all DWS production schemes. Characteristically, however, the total water cut for DWS is consistently greater than that for conventional wells over the whole process of recovery.

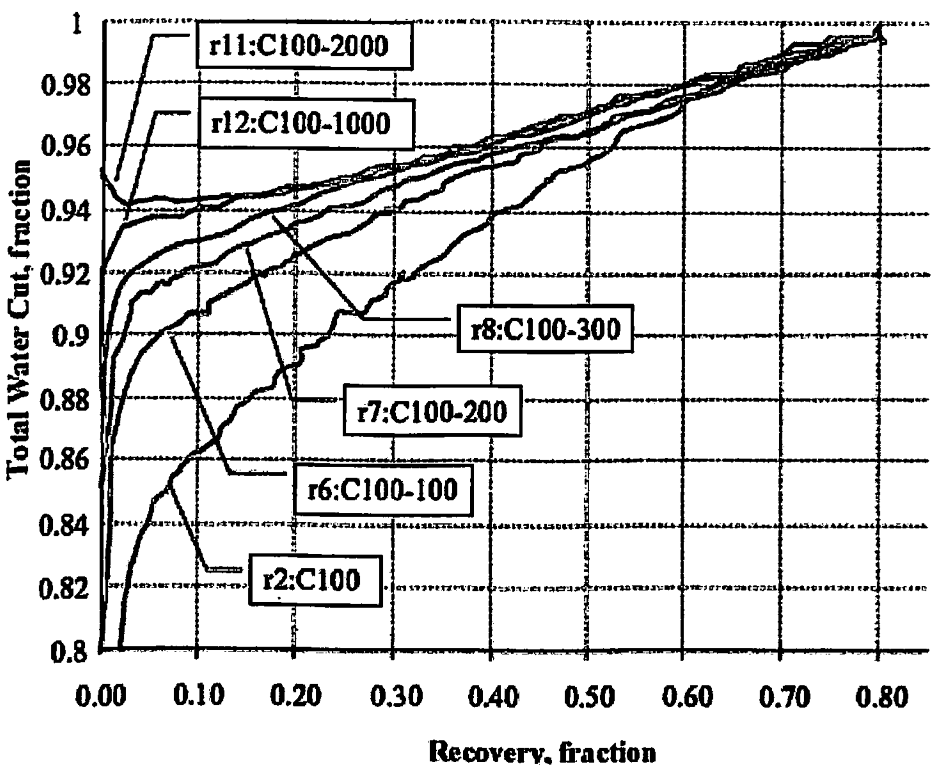


Figure 29: DWS recovers more oil with total water cut greater than conventional completion.

4.3 CUMULATIVE WATER WITHDRAWAL

Total volume of water withdrawn from the aquifer by DWS wells relates to the recovery time. These two criteria, production time and cumulative water withdrawal, were used in the the comparative analysis, presented below. Typically for wells with conventional completions, the higher the production rate is, the shorter the time to reach the economic limit of 98% water cut at the top perforations. In case r4:C400 in Table 3, 9.9 years were needed to reach the economic limit with recovery of 61% and 1,380,000 barrels of cumulative water. On the other hand, in Case r9: D200-200, 16.7 years were needed with 73% recovery and 2,350,000 barrels of water. Thus, DWS improved oil recovery by 12% on the expense of a 6.8-year longer production time and 970,000 barrels more of total produced water. Clearly, this comparison gives inconclusive results because it is made on the equal-fluid-rate basis. When the DWS bottom water drainage rate was increased from 200 BWPD to 1000 BWPD (Case r13: D200-1000 in Table 3), an 80-percent recovery was accomplished in only 7.8 years, with 3,340,000 barrels of water. These results show that though total water production with DWS is greater than that with single completions, it should not be considered in isolation from other production performance parameters such as the recovery factor or time. The simulation runs in Table 3 are summarized in Fig. 30 and Fig. 31. Analysis of these plots reveals that reduction of recovery time requires an increase of water production in both the conventional and DWS completions. However, DWS could accelerate the recovery process much more than a conventional well. As shown in Fig. 30 and Fig. 31, DWS production strategy could be optimized for maximum recovery, minimum time, and minimum cumulative water withdrawal.

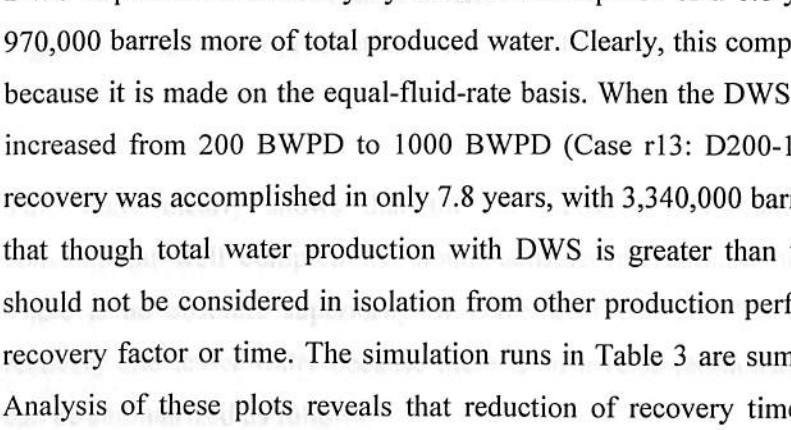


Figure 30: Recovery time decreasing with increasing DWS water drainage.

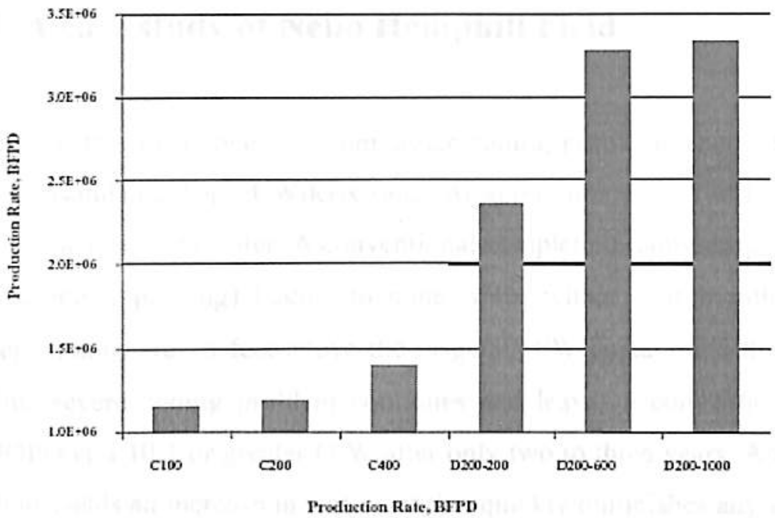


Figure 31: High water production is a trade-off for reduced recovery time.

This study clearly shows that the oil recovery performance comparison of DWS with conventional well completions should consider the amount of cumulative water withdrawal. There is no absolute superiority of DWS over conventional completions in terms of higher recovery and lesser water because there is an inverse relationship between the two. The results can be summarized as follows:

1. DWS could recover more oil in a shorter time than the conventional single completion by optimizing the combination of drainage-production rates.

2. For the same top production rate, recovery with DWS was 30% higher and fivefold shorter comparing to conventional completion;

3. For the same total production rate, recovery rates were equal – the DWS superiority stems from high and controlled water drainage;

4. Total water cut was almost equal for DWS and conventional well over 90% of the recovery process - at early times, total water cut for DWS was higher;

5. Conventional completion could either recover 61% of IOP in 9.9 years or 66% in 33.4 years - by reducing production rate; For the same reduced production rate, DWS could recover from 72% in 30.8 years up to 81% in 6.0 years by increasing the drainage rate.

6. DWS completely controls WC at the top completion, including WC reversal or its elimination;

7. Typically for DWS, total production WC is greater than that for conventional wells;

8. With increasing production of water, DWS can dramatically stimulate and accelerate the recovery process – water production with DWS should be optimized rather than minimized.

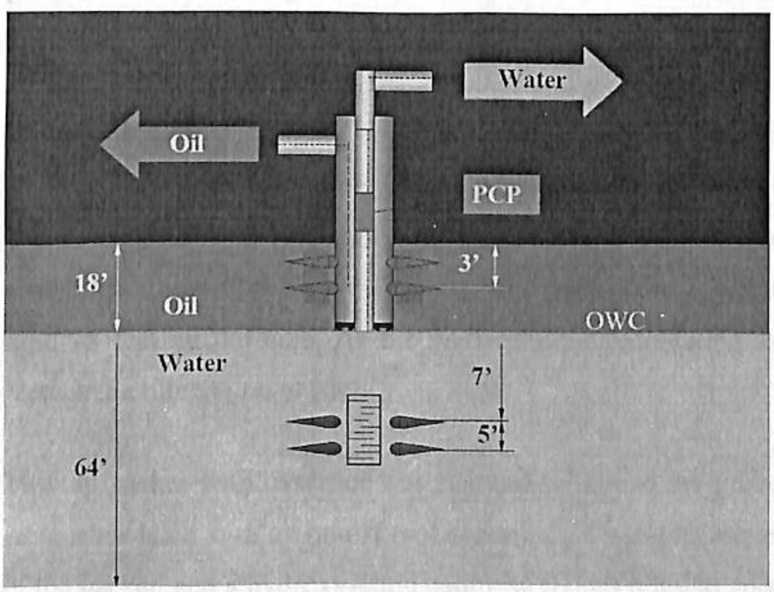
5. A case study of Nebo Hemphill Field

One of the most severe bottom water coning problems encountered in this field occurs in the unconsolidated Top of Wilcox sand. At approximately 2,500 feet, the oil is much more viscous than the produced water. A conventional completion (consisting of perforating the top of the sand and gravel packing) begins to cone water within four months, even though the production perforations are 15 feet above the original O/W contact and the well produces only 30 BOPD. This severe coning problem continues and leaves a conventional well making only 10 to 15 BOPD at a 10:1 or greater O/W after only two to three years. Any attempt to produce more total fluid yields an increase in water cut that quickly diminishes any increase in oil production. These low production rates, along with high water cuts, result in only 15 to 25 percent ultimate recovery of original oil in place (OOIP).

NEBO-HEMPHILL FIELD

(LaSalle Parish, LA)

•Wilcox sand; heavy oil (21-24oAPI, 17 cP);
•Strong water drive (1cP vis., 0.13 sat.)
•Water column: 10 -90% of the height;
•Unconsolidated clean sand (1-4 Darcy, φ=33%);



5.1 DWS Well Design

The DWS completion method was used to increase oil productivity and increase the amount of oil ultimately recovered in this field. The Top of Wilcox sand was selected to be the first place that the newly designed water drainage-production system would be tested.

Critical design factors for this method were oil production and water drainage rates, and vertical spacing between the oil and water perforations with regard to the oil-to-water contact (OWC). The LSU team of researchers developed computer-aided-design methods for DWS drainage-production and drainage-injection systems. A computer program based on a mathematical prediction of dynamic OWC calculated the operating range for the DWS well; a system Inflow Performance Window (IPW). The IPW required placing the water drainage perforations 10 feet below the original OWC, and expecting the producing water-to-oil ratio to be at least 30:1. This ratio was high mainly because of the large difference in the oil and water viscosities, and the high vertical to horizontal permeability ratio (assumed to be 0.9 in this very clean sand).

5.2 DWS Well Completion

A new well was drilled in December 1993 for this completion. It encountered 18 feet of oil column above 64 feet of water column. A seven-inch casing was set as the production string, and 3-1/2-inch tubing was used in the completion because of the large water-to-oil production ratio needed to prevent coning. The permeability in the upper part of the sand (where the oil perforations were thought to be) was 2,100 to 3,500 millidarcies (md). The permeability 10 feet below the O/W contact was 4,200 to 4,600 md.

Because this sand is highly unconsolidated, the lower water sink perforations had to be gravel packed. The first major completion problem was encountered when a dummy run with an overshot hit sand 38 feet above the hook-up nipple of the gravel pack screen. Apparently, the swabbing action of pulling the gravel pack packer out of the hole led to the formation heaving sand 38 feet up the hole. As the well continued sloughing sand, it took several extra days to replace the ruined gravel pack.

The top packer with overshot was run and set above the gravel packed water sink perforations. An anchor latch with an on-off tool containing a wireline retrievable plug was then set in the top of the packer, and a hydroxy-ethyl cellulose (HEC) pill was spotted across the oil zone. The top of the zone was then perforated with 12 shots per foot over a three-foot interval. The 3-1/2-inch production tubing was then run in the hole with the stator of a progressive cavity pump.

The well was then flowed up the tubing on a choke. The flowing tubing pressure would gradually drop from 100 pounds per square inch (psi) to zero after several hours of producing at two to four barrels per hour (BPH) oil. When this happened, oil was reversed down the casing to bring up any sloughing sand from the tubing string, and keep the casing annulus full of clean oil. Since we had perforated only the top three feet of sand, and were only pulling the oil zone at four BPH, the sand influx was expected to be limited. After several oil circulations throughout two days, the well cleaned up.

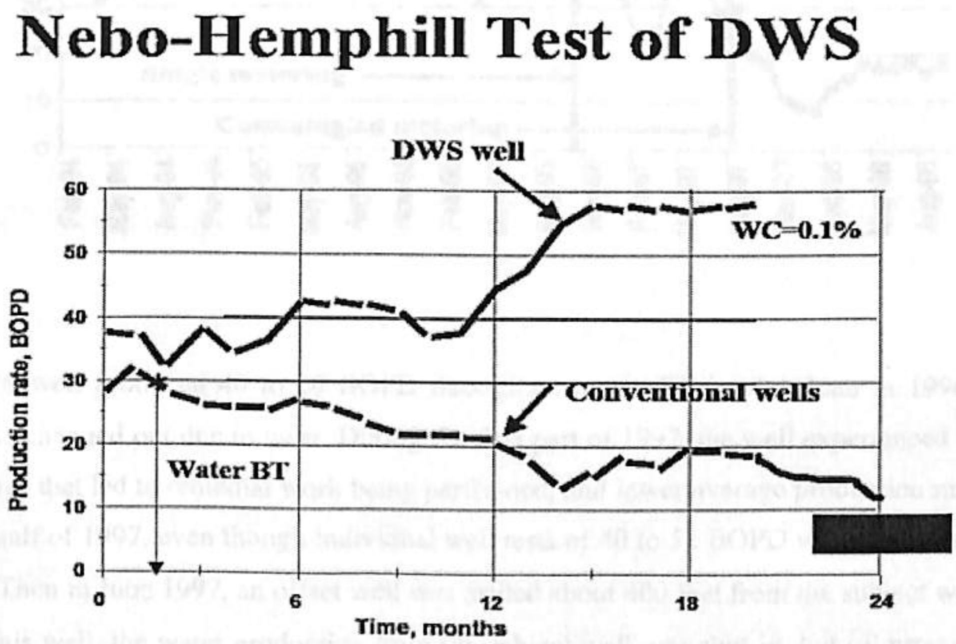
When the tubing was lowered to latch into the packer, the on-off tool would not engage, and the communication between the tubing and casing annulus remained. After failed attempts to solve the problem with slickline, the well had to be killed with 60 barrels of lease salt water in order to pull tubing. It was found that the sliding sleeve had fine threads in the body of the sleeve that had backed off while trying to un-J from the on-off tool. After displacing the well with oil, a severe sand production problem developed and it took three weeks and $43,000 to clean the well with a swab rig and the nitrogen tube trailer and jet the oil and sand out of the hole.

The tubing was lowered and latched into the on-off tool. The rotor of the progressive cavity pump was run in the hole with one-inch rods, and the water drainage perforations were put on production. After three days of producing 1,450 barrels of water per day (BWPD) up the tubing, the casing annulus was opened to a test tank to begin oil production from the top set of oil perforations. The well was potentiated at 48 BOPD and 1,472 BWPD one week after starting the oil production.

5.3 DWS Well Performance

During the first six weeks of production, the oil rate remained steady at 35 to 45 BOPD, 0.1 percent basic sediment and water (BS&W) and only a trace of sand, with 120 psi flowing casing pressure on an 8.5/64-inch choke. The oil flowed directly to the stock tank, where it was sold, and the drainage water was produced directly to the existing salt water system for disposal.

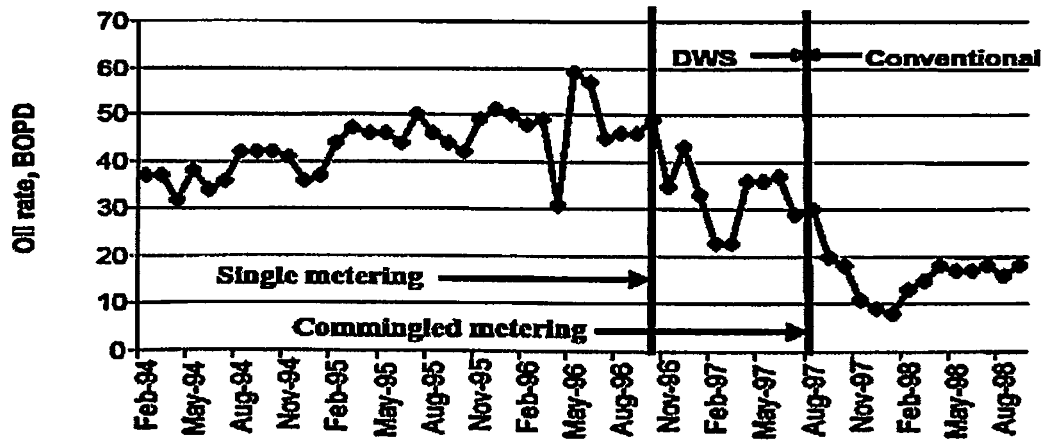
After six weeks, the well was treated for corrosion by pumping and displacing inhibitor down the tubing string. In subsequent weekly treatments, the casing pressure continued to drop after each treatment, until a water cut of 6 percent was established in the oil production. It was determined that since the formation had such high permeability, the small upset caused by pumping into the water zone, while the oil zone was producing, led to the O/W contact rising. To reverse the cone, corrosion treatments were discontinued, and the water rate was increased to 1,700 BWPD. After several weeks, the casing pressure had risen from 80 to 120 psi, and the BS&W content in the oil dropped back to 0.1 percent. This experience proved that the O/W contact can be controlled with this new completion method.



For six months, the well produced water-free oil and oil-free water. Eventually, it was decided to change the oil and water rates to increase productivity. In order to produce in excess of 40 BOPD without water breakthrough, the drainage water rate was increased to 2,000 BWPD. This was a 50:1 water/oil ratio, but since we had already experienced water breakthrough into the oil section of the reservoir, it took a higher ratio to bring the O/W contact back down. After several months of varying choke sizes and flow rates, it was determined that the well responded best to a flowrate of 55 to 60 BOPD, with a water drainage rate of 2,600 BWPD. This rate was established one year after the well had begun producing. After 17 months of production, the well was making 57

BOPD with 120 psi flowing casing pressure on a 9/64-inch choke, and the producing water/oil ratio of 33:1 compared very closely to the 30:1 ratio predicted by the computer model.

NEBO HEMPHILL TEST
Production History



The DWS well produced 40 to 50 BOPD throughout most of this trial. Late in 1996, the rod string was changed out due to wear. During the first part of 1997, the well experienced numerous rod failures that led to remedial work being performed, and lower average production rates during the first half of 1997, even though individual well tests of 40 to 52 BOPD were obtained between failures. Then in June 1997, an offset well was drilled about 400 feet from the subject well. While drilling this well, the water production from the subject well was shut in, but oil production was continued. This led to water coning into the oil production, and the well dying at about 27 percent water cut on the oil side. At this time, the well was recompleted as a conventional well by placing a plug in the isolation packer between the oil and water perforations, gravel packing the oil perforations, and returning the well to production with a rod pump. Then, typically for this field, the well's oil production rate dropped from the initial 30 to the present 17 BOPD, with corresponding water cut increase from 27 to 80 percent. If the were brought back to operation in DWS mode instead, it would most likely continue producing oil at the level of 40 to 50 BOPD .

OIL CONTENT IN PRODUCED WATER - Conventional vs. DWS Completions

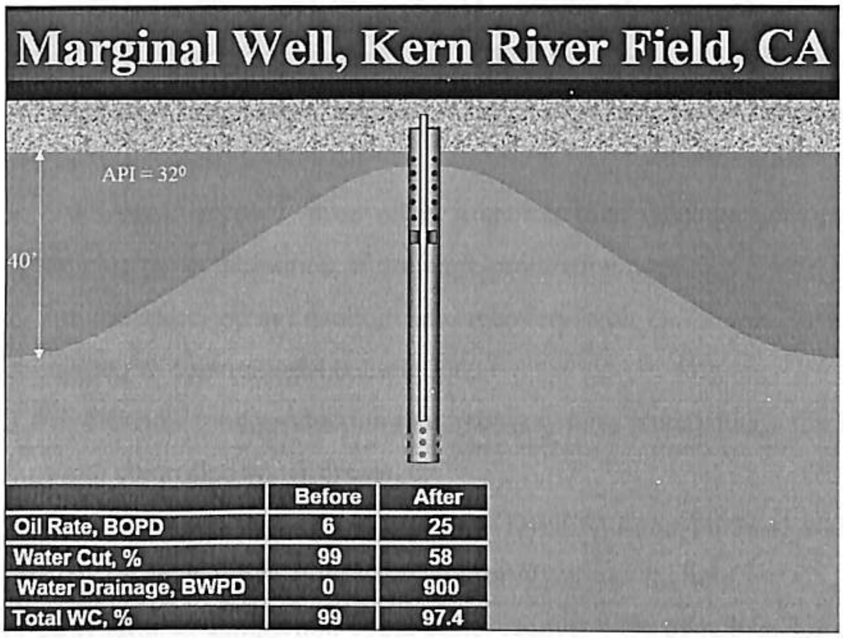
Parameter	Unit	Conventional	DWS
Total dissolved solids, TDS	mg/l	69,10063,	300
Oil and Grease	mg/l	484	Below Detection Limit
Polyaromatic Hydrocarbons	ppb	493	11

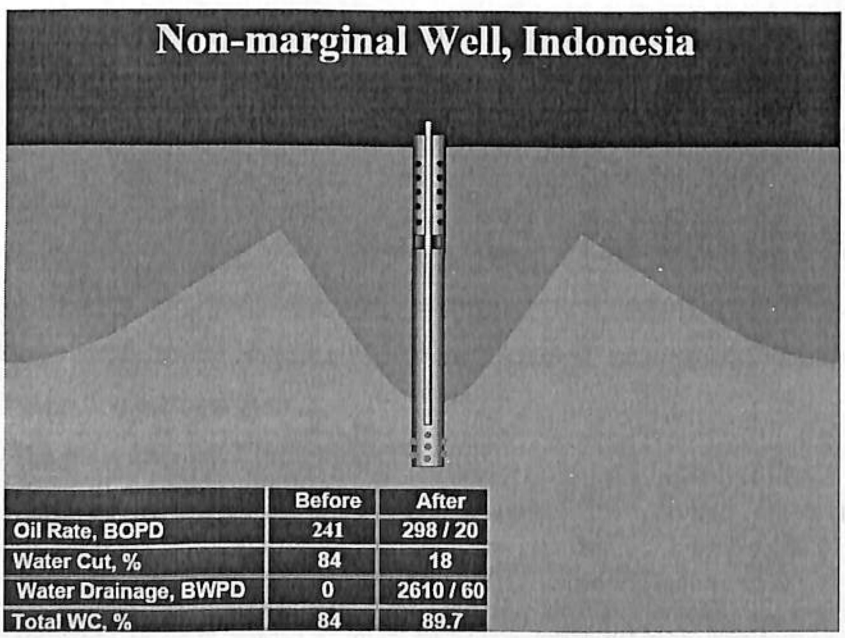
The cost of drilling and completing this trial well was about $267,000. A new well using a conventional completion with 5-1/2-inch casing and 2-7/8-inch tubing costs about $154,000. This difference was primarily due to having two sets of perforations, more downhole equipment, and more/larger tubulars. However, the payout of this new completion was as short or shorter than the conventional completions. Without the costs incurred from the two major problems, the new well would have paid out in 12 months, instead of 14. Knowing that oil production at 57 BOPD is possible, a new well using this completion and high initial rate would payout in less than eight months. This is about half the payout time of a conventional completion in this field.

At payout, this new completion was out-performing conventional completions by more than 3:1 with production at 55 BOPD, compared to the average rate 16 BOPD for conventional completions. The well also out-performed conventional completions by 5:1 in net monthly earnings, making $25,902 per month, compared to the average $7,006 per month for conventional wells.

An environmental objective of this test was to measure and compare hydrocarbon contaminations of waters from the new drainage-production system (drainage water) and conventional systems. The measurements showed that the level of oil and grease in the brine produced from conventional wells was 484 milligrams per liter, while for the DWS completion oil and grease was below the detection level of the U.S. Environmental Protection Agency-approved test. In view of present regulations, this water was far below National Pollutant Discharge Elimination System effluent discharge limitations and could be discharged with no treatment. Also, most of the polyaromatic hydrocarbons (PAH), which are most toxic and require advanced removal techniques, were not present in the brine produced from this completion. The very few PAHs detected were at low levels of 11 parts per billion; 50-fold less than those in the effluent from the conventional separation system.

5.4 RESULTS OF SOME OTHER OIL FIELDS WITH DWS TECHNOLOGY





CONCLUSION

This study clearly shows that the oil recovery performance comparison of DWS with conventional well completions should consider the amount of cumulative water withdrawal. There is no absolute superiority of DWS over conventional completions in terms of higher recovery and lesser water because there is an inverse relationship between the two. The results can be summarized as follows:

1. DWS could recover more oil in a shorter time than the conventional single completion by optimizing the combination of drainage-production rates.
2. For the same top production rate, recovery with DWS was 30% higher and fivefold shorter comparing to conventional completion;
3. For the same total production rate, recovery rates were equal – the DWS superiority stems from high and controlled water drainage;
4. Total water cut was almost equal for DWS and conventional well over 90% of the recovery process - at early times, total water cut for DWS was higher;
5. Conventional completion could either recover 61% of IOP in 9.9 years or 66% in 33.4 years - by reducing production rate; For the same reduced production rate, DWS could recover from 72% in 30.8 years up to 81% in 6.0 years by increasing the drainage rate.
6. DWS completely controls WC at the top completion, including WC reversal or its elimination;
7. Typically for DWS, total production WC is greater than that for conventional wells;
8. With increasing production of water, DWS can dramatically stimulate and accelerate the recovery process – water production with DWS should be optimized rather than minimized.

As evidenced in this study, the water coning control method has the advantages of increasing oil production rate, decreasing the water production rate and improving the oil recovery. However, these good results must be treated with caution because of the limitations of the mathematical simulation method used.

The most important limitations are:

(1) the inability of this model to simulate the oil and water production after the water breakthrough ; and

(2) lack of analytical representation of the oil/water transition zone and related effects of water saturation changes.

NOMENCLATURE

c = compressibility, 1/psi

g = gravity acceleration, cc/sec2

h = thickness, ft

h_w = water sink distance from OWC

k, k_v, k_h = permeability, spherical, vertical., horizontal, D

p = pressure, psi

p_b = formation pressure at OWC, psi

Qw = water production rate, bbl/day

Qo = oil production rate, bbl/day

r = radius, ft

r_D = dimensionless radius

r_{Da}= dimensionless reservoir radius

r_w = wellbore radius, ft

R - dimensionless ratio of gravity force to viscous

t =time, hour

t_D= dimensionless time

z = vertical distance between any point in the reservoir and oil sink, ft

y = water cone height at any point of water coning profile, ft

γ_w = water density, gram/cc3

p = viscosity, cp

Mo- oil viscosity, Cp

Ap = water-oil density difference, gram/cc3

ϕ = porosity, fraction

ϕ_w= Initial formation flow potential, psi

ϕ_d = dimensionless flow potential

REFERENCES

1. Wojtanowicz, A.K., Hui Xu, and Bassiouni, Z.: "Oilwell Coning Control Using Dual Completion With Tailpipe Water Sink," paper SPE 21654, Proceedings of the SPE Production Operations Symposium, Oklahoma City, Oklahoma, April 7-9, 1991.

2.Shirman, E.I. and Wojtanowicz, A.K.: "Water Coning Reversal Using Downhole Water Sink-Theory and Experimental Study," SPE 38792, Proc. 72nd Annual Technical Conference and Exhibition of SPE, San Antonio, Texas, October 5-8, 1997.

3.Shirman E. I. and Wojtanowicz A. K.: "More Oil with Less Water Using Downhole Water Sink Technology: A Feasibility Study," SPE 49052, Proc. 73rd Annual Technical Conference and Exhibition of SPE, New Orleans, LA, October 27-30, 1998.

4.Swisher, M.D. and Wojtanowicz, A.K.: "New Dual Completion Method Eliminates Bottomhole Water Coning," SPE paper 30697, Proc. SPE Annual Technical Conference and Exhibition, Dallas, TX, October 22-25, 1995, 549-555.

5.Loginov, A. and Shaw, C.: "Completion Design for Downhole Water and oil Separation and Invert Coning," SPE 38829, Proc. 72nd Annual Technical Conference and Exhibition of SPE, San Antonio, Texas, October 5-8, 1997, also, JPT, March 1998, 70 -73.

6.Byrne, W.B. Jr. and Morse, R.A.: "The effect of Various Reservoir and Well Parameters on Water Coning performance" paper SPE 4287 presented at the Third Numerical Simulation of Reservoir Performance Symposium of SPE in Houston, TX, Jan. 10-12, 1973.

7.Shirman, E.I.: "Experimental And Theoretical Study Of Dynamic Water Control In Oil Wells" Ph.D. Dissertation in Department Of Petroleum Engineering, Louisiana State University, 1998.

8.TAREK AHMED : "RESERVOIR ENGINEERING HANDBOOK-chapter number nine"

9.L. P. DAKE : "FUNDAMENTALS OF RESERVOIR ENGINEERING –chapter number nine"

10. www.service-halliburton.com, www.slb.com, www.westerngeco.com, www.pttc.org, www.winkiepedia.com, www.spe.org