Oil and Water Production in a Reservoir With Significant Capillary Transition Zone

R.N. Reed, SPE, Clyde Petroleum plc
M.J. Wheatley, SPE, Clyde Petroleum plc

Summary

Analytical and numerical methods are used to investigate the mechanism of water production in a high-permeability sandstone reservoir that has a capillary transition zone height comparable to formation thickness. Production rates are well above those for transition-zone water production alone. Consequently all wells are affected by coning shortly after the start of production.

It is found that water cut is largely insensitive to total fluid production rate for the same recovery. The depth of well penetration and the effect of radial capillary pressure gradients are shown to be of secondary importance in these circumstances. The predictions are confirmed by the results of a long-term pilot production test.

Introduction

This paper considers the mechanism of water production in a highly permeable sandstone reservoir with a 22°API [0.9-g/cm³] undersaturated oil and a strong edge aquifer drive. The findings are drawn from a study recently performed on the M-1 Sand reservoir of the Fanny field, which is located on the eastern flank of the Oriente basin in Ecuador. M-1 Sand belongs to the Napo formation of the Cretaceous Age and consists of moderately to poorly cemented quartzose sands of high permeability. Reservoir depth is approximately 7,700 ft [2347 m].

A characteristic feature of the reservoir is the wells’ predisposition to develop substantial water cuts after short periods of production. Attempts have been made in the past to reduce water production by squeeze cement jobs and recompletions. However, these operations have not been effective for the very short term and consequently the study has concentrated on attempting to define the nature of fluid movement within the drainage area of the wells.

Reservoir Description

M-1 Sand shows lithological features characteristic of a fluvial channel depositional environment. These features are exemplified by the Induction Electrical Survey of Well 18-B-2 (Fig. 1), which shows a basal unit 45 to 55 ft [14 to 17 m] thick, overlain by a variable number of smaller units that are separated by shale breaks and tight streaks. These upper units are of poor quality and limited lateral continuity. In contrast the basal unit contains no correlatable shale breaks although thin shales were encountered in some wells and early completion practices attempted unsuccessfully to make use of them. Because of this early experience and the absence of correlation it has been concluded that such shale breaks are of limited lateral extent and do not contribute materially to the prevention of water-cone development.

The basal unit contains more than 90% of the original oil in place, estimated at 48x10⁶ STB [7.6 x 10⁶ stock-tank m³]. Currently all wells are completed in this unit, which has provided all production to date. The upper units have been neglected for the purposes of this paper.

The structural configuration of the reservoir is a faulted asymmetrical anticline of low structural amplitude. Fig. 2 represents the structure on top of the basal sand unit and shows the intersection of the oil/water contact (OWC) with the surface, giving rise to a maximum oil column of 65 to 70 ft [20 to 21 m]. A comparison of sand thickness with oil column height indicates that the base of the sand is everywhere close to the OWC and that all wells have high basal water saturations. Pressure support is by edge aquifer influx, but with strong underrunning giving behavior characteristic of a bottom aquifer.

Reservoir and Fluid Properties

The basal unit is variable in quality but characterized by high porosity and permeability averaging 20 to 25% and 2 to 3 darcies, respectively. Figs. 3 and 4 are capillary-pressure and relative-permeability curves representative of the basal unit. These curves are typical of a sandstone that contains large, well-interconnected pores. Sands of this unit are generally poorly cemented and friable. No fractures are evident from either cores or logs. There is no evidence of any fracture-induced effects on pressure buildup data, which correspond to a single permeability intergranular system.

Average oil and water fluid properties are presented in Table 1. The oil and water viscosities at reservoir conditions are 12 and 0.35 cp [12 and 0.35 inPa·s] respectively, which give a very unfavorable endpoint mobility ratio. The displacement of oil by the encroaching aquifer is thus an unstable displacement and the strong underrunning of water quickly results in high producing water cuts in the wells.
The combination of a moderately heavy oil with a low-density fresh formation water gives a small fluid density difference of 0.057 psi/ft [1.29 kPa/m] at reservoir conditions. This results in an appreciable transition zone despite the low values of capillary pressure evident from Fig. 3. Since the OWC is close to the base of the formation, most of the gross oil column lies within the transition zone.

Log analysis of the eight producing wells reveals a significant transition zone, in agreement with the capillary pressure data. Also evident from the log analysis is a vertical fluctuation in calculated water saturation within a section of apparently clean sand. The degree of fluctuation varies from well to well (shown by a comparison of Figs. 5 and 6) and is ascribed to variation in sand grain size and degree of cementation. This aspect is of some importance because it relates to the production pattern of wells within this field.

Well Production History

Typically individual flowing well production is characterized by a few months of very low water production (water cut around 1 to 5%), followed by a period of rapidly increasing water cut and declining total fluid production. A period of stabilized production then follows, with water cut increasing slowly over a period of years.

This does not conform to a typical water-coning behavior pattern because (1) initial water production is always present, (2) the period of time to breakthrough is not related uniquely to structural elevation and production rate, and (3) the value of water cut during the initial period of production following breakthrough is not related uniquely to structural elevation and production rate.

It has been found, however, that a given well's production performance is related intimately to the initial saturation distribution of that well. This is exemplified by reference to the two wells shown in Figs. 5 and 6. Previous documentary evidence has suggested that prolonged flow of formation water within a sand can in some instances lead to the precipitation of a crust of
radioactive salts in the vicinity of the wellbore. A zone of water production can thus be identified by a comparison of successive gamma ray logs taken over a long period of production. This approach has been particularly useful in determining the development of water production from wells of the Fanny field. In wells with a uniform transition zone (Fig. 5), mobile water exists throughout the formation. However, the principal region of water movement is along a basal zone of high water saturation corresponding to that part of the reservoir with highest water mobility. Wells of this type display a longer period of production at low water cuts and have a lower value of stabilized water cut postbreakthrough. Other wells that show significant variation in saturation distribution and a high average initial water saturation (Fig. 6) are subject to production of significant water from all levels of the sand. These wells are characterized by rapid or immediate breakthrough to high levels of water cut. While there is obviously a structural element to the previously described patterns it has been found that within the transition zone the variations in sand quality and thickness are of equal significance in determining the initial saturation distribution and hence well performance.

### Prediction of Well Performance

For the wells with obvious bottomwater production it would seem that performance might be predictable with the use of conventional coning models, even though there is some initial water movement throughout the oil column. If this transition-zone water production is ignored, then a critical rate formula that is appropriate for segregated flow conditions may be used to estimate the rate below which there will be no coned water production. Such a formula is the Dupuit formula, which in field units is

\[
q_c = \pi k_b \Delta \gamma \lambda_o (h_o - h_w)^2 / 887.2 \ln r_o / r_w, \quad \ldots \ldots (1)
\]

where \(h_c\) is the well penetration and \(h_o\) is the oil column thickness. To apply Eq. 1 to a reservoir with a transition zone, \(h_w\) is adjusted to give the correct average oil saturation and \(\lambda_o\) is obtained by averaging relative permeability over reservoir thickness. For the conditions of Well 18-B-2 the average values obtained for \(h_w\) and \(\lambda_o\) are 46 ft [14 m] and 0.05 cm \(^{-1}\) [0.05 mPa-s \(^{-1}\)], respectively. Then with \(h_c = 13\) ft [4 m] (25% penetration) and with the data given in Table 2, Eq. 1 gives \(q_c = 9\) B/D [1.3 m \(^3\)/d] compared with a typical total fluid production rate of 600 B/D [95 m \(^3\)/d] for Well 18-B-2. Even though we have not accounted for a vertical-to-horizontal permeability contrast of 0.1, it is clear that economical production rates are well above the critical rate for no coning so that significant water production is inevitable.

A correlation to predict the time taken for a water cone to develop is given by Sobociński. Unfortunately values of parameters relevant to the Fanny reservoir M-1 Sand are outside the range of applicability of the correlation. Because of this and the uncertain effect of the capillary transition zone we decided to use a numerical reservoir simulator to model the performance of one well. Well 18-B-2 (see Fig. 2) was chosen for the study since it had the longest uninterrupted production history. The well also has above average reservoir properties with 4-darcy average permeability, 22% average porosity, and 23% average initial water saturation.

A Beta II* model was used for the study. Because this model does not permit the use of separate capillary pressure data for the initialization and prediction stages of the simulation, the drainage capillary pressure data shown in Fig. 3 were used in the model to obtain the correct initial fluid distribution. The imbibition curves shown in Fig. 4 were used for the water-oil relative permeabilities. Other input data are summarized in Table 2.

A history match was performed to quantify such factors as aquifer strength and vertical-to-horizontal permeability ratio. A number of prediction cases were run to determine likely future performance of the well. The model also was used in a more general way to investigate the comparative effects on oil recovery and water cut of different production rates and perforated intervals applied from the start of production. The results are shown in Fig. 7 in terms of water cut vs. cumulative oil recovery. The following features are apparent from this diagram.

1. The relationship between water cut and oil recovery is largely independent of depth of well penetration.
2. The relationship between water cut and oil recovery is generally insensitive to total fluid production rate.

These findings may seem surprising but are predicted by the analytical coning model of Chappelear and Hirazaki for cases where the total fluid production rate is large (see Appendix A). Similar conclusions have also been noted by other authors for a variety of reservoir conditions.

The simulation results shown in Fig. 7 indicate that recovery for a given water cut is slightly higher for higher production rates. The coning model, however, predicts the opposite effect (see Eq. A-1). The difference arises because capillary pressure effects are ignored in the derivation of the Chappelear-Hirasaki model. This is demonstrated in Appendix B, where the effect of capillary pressure on radial flow into a well is examined.

### Table 1—AVERAGE FLUID PROPERTIES

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir pressure at 6950 ft, psig</td>
<td>3,270</td>
</tr>
<tr>
<td>Reservoir temperature at 6950 ft, °F</td>
<td>139</td>
</tr>
<tr>
<td>Saturation pressure, psig</td>
<td>570</td>
</tr>
<tr>
<td>Properties at Surface Conditions</td>
<td></td>
</tr>
<tr>
<td>Stock-tank oil gravity, °API</td>
<td>22.5</td>
</tr>
<tr>
<td>Gas gravity</td>
<td>1.2</td>
</tr>
<tr>
<td>GOR, scf/STB</td>
<td>95</td>
</tr>
<tr>
<td>Formation water total dissolved solids, mg/L</td>
<td>25,500</td>
</tr>
<tr>
<td>Properties at Reservoir Conditions</td>
<td></td>
</tr>
<tr>
<td>Oil formation volume factor, RB/STB</td>
<td>1.1</td>
</tr>
<tr>
<td>Oil density, lbm/cu ft</td>
<td>53.64</td>
</tr>
<tr>
<td>Oil viscosity, cp</td>
<td>11.8</td>
</tr>
<tr>
<td>Water formation volume factor, RB/STB</td>
<td>1.03</td>
</tr>
<tr>
<td>Water density</td>
<td>61.83</td>
</tr>
<tr>
<td>Water viscosity, cp</td>
<td>0.35</td>
</tr>
</tbody>
</table>

The results of Appendix B, obtained by assuming one-dimensional (1D) flow with capillary pressure and vertically averaged pseudorelative permeabilities broadly agree with the two-dimensional model studies whose results are shown in Fig. 7. A rough estimate of a well’s performance may, therefore, be obtained by using the 1D approach. Also, since radial capillary effects are of secondary importance they may be ignored, which enables the analytical Buckley-Leverett theory to be used to predict performance approximately.

If a more precise description of the well’s behavior is desired then neither the Buckley-Leverett theory nor the analytical coning model is applicable and it is necessary to employ a numerical simulation approach.

Pilot Studies

In an attempt to verify the results of the foregoing simulation work a pilot production test was initiated on one of the Fanny field wells. The well (Fanny 5) has generally poor reservoir characteristics; it is structurally low and has a thin basal sand unit (34 ft [10 m]), although permeabilities are somewhat better than average. The resulting average water saturation is higher than for other wells in the field and consequently no initial period of low-water-cut production was recorded. Following cleanup, the well achieved 89 B/D [14 m³/d] oil with 77% water cut on initial lift.

A single-well simulation study was performed on this well by using the Beta II program. The insensitivity of the water-cut/recovery relationship to production rate described previously was also observed in this simulation (see Fig. 8). The feature of slightly higher recovery for a given water cut at the higher production rate is again apparent. Fig. 9 shows the water cut as a function of oil recovery predicted by Buckley-Leverett theory with the appropriate pseudorelative permeability curves. Again the results are similar to the simulation. An almost immediate water cut of around 75% is predicted, followed by a slow increase in cut with increasing recovery.

In conducting the pilot test the use of artificial lift has permitted production rate control to within fairly close tolerances. Therefore, it has been possible to monitor in detail water-cut changes brought about by production rate changes. A base case production rate of 610 B/D [97 m³/d] total fluid with 77% water cut was held constant for three months at the beginning of 1983 and monitored daily to establish a trend. Total fluid offtake was increased to 1,500 B/D [238 m³/d] at the end of March 1983 and has run close to that since then. The results are displayed in Fig. 10, which shows the daily production figures averaged on a weekly basis. It can be seen that 2 months after the increase in production rate the water cut had decreased to around 75% and stayed at that level for about 7 months. The water cut subsequently has risen, which corresponds to the expected increase with cumulative production. This behavior is in qualitative agreement with the simulation results shown in Fig. 8. The simulations for the Fanny 5 well were conducted before initiation of the pilot test and the production rates used in the study were different from the actual pilot test rates.

**TABLE 2—SINGLE WELL SIMULATION INPUT DATA FOR A 2D HORIZONTAL r-z GRID SYSTEM**

| Number of grid blocks in radial direction | 8 |
| Number of grid blocks in vertical direction | 6 |
| Well radius, \( r_w \), ft | 0.3 |
| Outer radius, \( r_o \), ft | 1,500 |
| Ratio of consecutive grid block outer radii | 2.43 |
| Horizontal air permeability, \( k_h \) (all blocks), md | 4,000 |
| Vertical permeability, \( k_v \) (all blocks), md | 400 |
| Layer thickness, ft | 13, 13, 7, 7, 7, 5 |
| Layer porosities, % | 20, 22, 21, 15, 15, 28 |
| Edge aquifer influx per layer, B/D/psi | 2.5, 2.5, 1.3, 1.3, 1.3, 1 |

**Fig. 7—Simulator predicted water cut vs. oil recovery for Well 18-B-2.**
The effect of increased production rate has been tested recently on a second well in the field. This is Well 18-B-3, which produced on artificial lift at a stabilized rate of 370 B/D [59 m³/d] oil with a 57% water cut before rate increase in Oct. 1983. The well has averaged 58% water cut following an increase in fluid production rate from 860 to 1,350 B/D [137 to 215 m³/d] fluid.

The testing scheme currently is being expanded to a third well in conjunction with a regular series of pressure buildsups in nearby wells, which are being used to monitor the effects of these rate changes on average reservoir pressure.

Discussion

Study of individual well performance has highlighted a number of salient features relevant to the nature of water production from wells in this reservoir. The two principal features are (1) economical production rates are such that high water production is inevitable and (2) recovery is unaffected by the total rate of fluid production. Water cuts then are determined largely by the average fractional flow, and hence average saturation, of water within the drainage area of the well. Consequently, structural elevation, sand quality, and thickness are the main factors affecting well performance, irrespective of the total production rate.

The implications of these findings for reservoir development and management are threefold.

1. The concept of recompleting wells at higher levels within the reservoir to avoid coning is not valid in this situation.

2. Wells should be produced at as high a rate as possible.

3. Increasing the drawdowns in reservoirs of high permeability provides the dual economic advantages of accelerating production without harming per-well recoveries and permitting larger well spacing without reducing overall recovery from the reservoir.

The major constraint imposed on the application of these concepts is pressure maintenance; if the supporting aquifer cannot sustain the higher off-take rates, water injection would be required. In common with a number of fields in the Oriente region the Fanny field M-1 Sand is supported by a vigorous aquifer. Fig. 11 shows the reservoir pressure history recorded in four flowing wells and indicates a maximum average reservoir pressure decline...
of around 110 psi [758 kPa] in 1981 for a stabilized total fluid production rate of 3800 B/D [604 m3/d]. Pressure subsequently has risen in response to declining total fluid offtake from the flowing wells, which was caused by higher producing water cuts. The recent reversal of the trend is thought to be related to increased offtake from the pilot study well.

The level of pressure support supplied by this aquifer is such that the installation of water injection facilities to provide pressure maintenance at higher offtake rates clearly is not required.

Conclusions

For homogeneous reservoirs where the transition-zone height is comparable to the oil column thickness and where production rates are substantially above the limiting rates to prevent coning, the following conclusions apply.

1. The relationship between cumulative oil recovery and water cut is largely independent of well penetration.
2. The relationship between cumulative oil recovery and water cut is generally insensitive to production rate.
3. The water cut is principally dependent on the average fractional flow of water and thus the average water saturation in the drainage area of the well.
4. The insensitivity of oil recovery to fluid production rate allows maximization of oil production without affecting ultimate recovery. The resulting increased drawdowns that are permissible under this regime additionally allow a greater well spacing with consequent economic advantages.
5. A secondary effect, which occurs when reservoir dip is small, is the tendency for improved recovery at a given water cut for higher production rates because of the development of a radial capillary pressure gradient.

Nomenclature

\[
A = \text{coefficient defined by Eq. A-4, B/D/sq ft [m/d]}
\]
\[
B = \text{coefficient defined by Eq. B-3, ft/psi [m/kPa]}
\]
\[
f_w = \text{fractional flow of water}
\]
\[
f_{wa} = \text{average fractional flow of water within drainage area}
\]
\[
f_{wi} = \text{fractional flow of water at initial conditions}
\]
\[
h_o = \text{average height of oil column, ft [m]}
\]
\[
h_c = \text{depth of completed interval, ft [m]}
\]
\[
h_r = \text{reservoir thickness, ft [m]}
\]
\[
k_o = \text{horizontal permeability, md}
\]
\[
M = \text{ratio of water mobility at residual oil saturation to oil mobility at connate water saturation}
\]
\[
P_c = \text{oil-water capillary pressure, psi [kPa]}
\]
\[
P_{ci} = \text{capillary pressure at initial conditions, psi [kPa]}
\]
\[
q_c = \text{critical rate for low water production, B/D [m}^3/\text{d]}
\]
\[
q_T = \text{total fluid production rate, B/D [m}^3/\text{d]}
\]
\[
r = \text{radial distance from well, ft [m]}
\]
\[
\log r_a = \text{radius term defined by Eq. A-5, ft [m]}
\]
\[
r_e = \text{external (drainage) radius, ft [m]}
\]
\[
r_w = \text{well radius, ft [m]}
\]
\[
S_w = \text{water saturation}
\]
\[
t = \text{time, days}
\]
\[
\Delta \gamma = \text{difference in water and oil fluid gradients, psi/ft [kPa/m]}
\]
\[
\lambda_o = \text{oil mobility, cp}^{-1} \text{[mPa} \cdot \text{s}^{-1}]
\]
\[
\lambda_w = \text{water mobility, cp}^{-1} \text{[mPa} \cdot \text{s}^{-1}]
\]
\[
\phi = \text{porosity, fraction}
\]

Acknowledgments

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References


APPENDIX A

Oil-Water Coning Model

A model for oil-water coning into a partially penetrating well has been given by Chappelear and Hirasaki. They consider a radially symmetric, homogeneous, incompressible, nondipping system with oil and water influx at the outer boundary and corresponding production at the well (see Fig. A-1). Vertical equilibrium, segregated flow, and steady-state conditions are also assumed. Their result is presented here for the case of no initial bottom water, completed interval extending to the top of the formation, and high total fluid flow rate, q_T.

![Fig. A-1—Analytical coning model geometry and symbols.](image-url)
The coning model is then the following equation relating water cut at the perforations, \( f_w \), to the average oil column thickness, \( h_a \), and the well penetration, \( h_c \):

\[
f_w = f_{wa} \left[ 1 - Ah_a^2 \left( 1 - h_c/h_i \right)/q_i \right], \quad (A-1)
\]

where

\[
f_{wa} = \left[ 1 + h_a/M(h_i - h_a) \right]^{-1}, \quad (A-2)
\]

in which \( M \) is the endpoint mobility ratio and \( f_{wa} \) is the average fractional flow of water within the drainage area of the well.

Eq. A-1 is a simplified form of the original expression and is valid for flow rates such that

\[
q_i > Ah_a^2. \quad (A-3)
\]

The coefficient \( A \) is given by:

\[
A = 2\pi k_r \lambda_s \Delta \gamma/887.2 \ln r_a, \quad (A-4)
\]

where

\[
\ln r_a = \ln (r_e/r_w)/\left[ 1 - (r_w/r_e)^2 \right] - 1/2. \quad (A-5)
\]

When the average OWC is below the completed interval, Chappelear and Hirasaki include an effective well radius in the above term. This also appears in their expression for critical rate. However, we feel that an effective well penetration corresponding to the effective well radius should then be used in their expression for critical rate and also in Eq. A-1. Since there is no convenient way to estimate this from the theory presented in Ref. 4, we have omitted the effective radius from Eq. A-5. The value of the term \( Ah_a^2 \) is then 21.3 B/D [3.4 \( m^3/d \)] for the conditions of Well 18-B-2 compared with total production for this well of about 600 B/D [95 \( m^3/d \)]. This confirms that \( Ah_a^2 \) is much smaller in magnitude than \( q_i \).

Since Eq. A-1 is applicable for rates greater than \( Ah_a^2 \), the producing water cut, \( f_w \), is then seen to depend principally on \( f_{wa} \), and the dependence becomes more pronounced with increasing oil recovery (smaller \( h_a \)). Production rate and well penetration thus have only a secondary effect on the producing water cut.

**APPENDIX B**

**Radial Flow With Capillary Pressure**

To illustrate how capillary pressure influences the flow into a well a simplified 1D, incompressible radial system with constant aquifer influx at the outer boundary is considered. Vertical variations of saturation are accounted for by averaging relative permeabilities, capillary pressures, and saturations over the thickness of the reservoir in the manner described by Dake.\(^9\)

In terms of these averaged functions, the usual fractional flow equation takes the form

\[
f_w = f_{wa} + B\partial \left( P_c - P_e \right)/\partial r, \quad (B-1)
\]
where

\[ f_{w1} = \frac{\lambda_w}{(\lambda_w + \lambda_o)} \]  \hspace{1cm} (B-2)

and where, in field units,

\[ B = 0.0071k_p f_{w1} \rho_0 r/q_i \]  \hspace{1cm} (B-3)

In Eq. B–1, \( f_{w1} \) and \( P_{ci} \) are the fractional flows and pseudocapillary pressures that correspond to the initial saturation distribution.

As production proceeds there is an increase in water saturation caused by aquifer influx. The development of the flow is governed by the conservation equation for water—namely,

\[ \frac{\partial S_w}{\partial t} = 0.893 \frac{q_i}{(\phi h_i) \partial f_{w1}/dr} \]  \hspace{1cm} (B-4)

This has been solved numerically for Well 18-B-2 conditions by using the vertically averaged pseudocurves presented in Figs. B–1 and B–2. The slight reservoir dip was ignored and the initial saturation distribution used was a constant 23.5%.

Fig. B–3 shows the results obtained for fractional flow vs. recovery with a constant total flow rate of 500 B/D [80 m³/d]. This is compared with the analytical Buckley-Leverett solution, which, since this neglects capillary pressure, corresponds to the limiting case of very high rate (see Eq. B–1). It can be seen that water cut is less at higher flow rates for the same recovery.

The reason for this can be inferred from Fig. B–4, which compares the radial variation in average water saturations. The effect of capillary pressure is to disperse the influx from the aquifer. With large flow rates this dispersion is low resulting in higher water saturations adjacent to the aquifer than is the case with lower rates. For the same recovery the water saturation is correspondingly lower near the well with the higher rates and this gives a lower producing water cut.

**SI Metric Conversion Factors**

\begin{align*}
{^\circ}API & \quad 141.5/(131.5 + {^\circ}API) = g/cm^3 \\
bbl & \times 1.589 873 \quad E-01 = m^3 \\
cp & \times 1.0^{\ast} \quad E-03 = \text{Pa}s \\
cu ft & \times 2.831 685 \quad E-02 = m^3 \\
ft & \times 3.048^{\ast} \quad E-01 = m \\
{^\circ}F & \quad (^\circ F – 32)/1.8 \quad = ^\circ C \\
ibm & \times 4.535 924 \quad E-01 = kg \\
mL & \times 1.0^{\ast} \quad E+00 = cm^3 \\
psi & \times 6.894 757 \quad E+00 = kPa
\end{align*}

*Conversion factor is exact.*

Fig. 7—Predicted water cut vs. oil recovery for Well 18-B-2.

Fig. 8—Predicted water cut vs. oil recovery for pilot test well.

Fig. 9—Results of pilot study.

Fig. 10—Fanny field pressure history.
Fig. 14—Water cut vs. oil recovery for Well 18-B-2 predicted using pseudocurves.

Fig. 15—Radial water saturation distribution for Well 18-B-2.