Case Study of a Low-Permeability Volatile Oil Field Using Individual-Well Advanced Decline Curve Analysis


SPE Members

ABSTRACT

This paper presents a detailed case history study of a low permeability volatile oil field located in Campbell County, Wyoming. The field was analyzed on an individual well basis using advanced decline curve analysis for 40 individual well completions. Well permeabilities, skins and original oil in place are calculated for each well from rate-time analysis using constant wellbore pressure type curve analysis techniques.

Original oil in place values calculated from rate-time analysis for individual wells are used with recoverable reserve projections from the decline analysis to obtain fractional recoveries for each well. Gas-oil ratios versus fractional recovery curves are also made for each well using historical cumulative production and the calculated oil in place values. Ultimate fractional recovery numbers and GOR vs fractional recovery curves, plotted for each well, are shown to suggest different rock types and reservoir fluids. Multi-well decline curve analysis shows the validity of the variables s (skin), k, OOIP, ultimate fractional recovery and GOR vs fractional recovery evaluated from each well's type curve evaluation. These variables must all give consistent and reasonable numbers when compared with each other. A single well analysis can easily give results that are not recognized as being invalid unless compared with other wells in the field.

The study also illustrates flowing and pumping well backpressure changes in a well's decline, the method of handling such changes, and their effect on ultimate recoverable reserves predictions. Conventional decline curve analysis can not handle backpressure changes because of its constraint that what controls the decline in the past will also continue in the future.

INTRODUCTION

In solution gas drive reservoirs, decline curve analysis of rate-time data for predicting future production and determining recoverable reserves for a fairly large number of wells is commonly done using the Arps\(^1\) empirical equations and a computerized statistical approach to arrive at answers fairly quickly. For wells in high permeability reservoirs producing essentially wide-open, without future backpressure changes and without future stimulation treatments, the results obtained should be reasonably good providing the limits of the decline exponent b of between 0 and 1.0 are honored.

At the other extreme in analyzing rate-time data for predicting future production and recoverable reserves, a reservoir simulation study could be undertaken. However, this approach could take as much as a year to accomplish and normally would not be considered acceptable, particularly for time-constrained property acquisition or sales situations where few of the detailed reservoir parameters necessary for a simulation study are available.

Many of the newer oil and gas fields being discovered and produced are in the low permeability classification, where transient behavior can last for years, and therefore are not amenable to analysis using the Arps equation alone. Also, a model study of such low permeability reservoirs would require a very fine grid system to correctly simulate and match the early transient rate-time decline data.

An approach to the problem of analyzing low permeability wells and total field rate-time decline has been given in papers\(^2\) \(^3\) \(^4\) \(^5\) \(^6\) that illustrate methods of handling both the transient and depletion stages of rate-time decline. Well permeabilities, skins from stimulation treatments and original oil in place or original gas-in-place can be calculated for each well from rate-time data using constant wellbore pressure type curve analysis techniques.

References and Illustrations at end of paper.
With a field case study of the School Creek Field in Campbell County, Wyoming, a low permeability volatile oil field, we will present a stepwise procedure for doing a total field study using individual well advanced decline curve analysis techniques. Original oil in place values calculated from rate-time analysis for individual wells are used with recoverable reserve projections from the decline analysis to obtain fractional recoveries for each well. Gas-oil ratio versus fractional recovery curves are also made for each well using historical cumulative production and the calculated oil in place values. Ultimate fractional recovery values and GOR versus fractional recovery curves, plotted for each well, are shown to suggest different rock types and reservoir fluids. Multi-well decline curve analysis shows the validity of the variables s (skin), k, OOIP, ultimate fractional recovery and GOR versus fractional recovery evaluated from each well's type curve match point. These variables must all give consistent and reasonable numbers when compared with each other. A single well analysis can often give results that are not recognized as being invalid unless compared with several other wells in the field. The study also includes and illustrates flowing and pumping well backpressure changes in a well's decline, the method of handling such changes and their effect on ultimate recoverable reserve predictions. Conventional decline curve analysis approaches do not consider backpressure changes and their effect on projected recoverable reserves.

School Creek Field - Wyoming

The School Creek Field is located on the eastern flank of the southernmost part of the Powder River Basin in Campbell and Converse Counties, Wyoming. Following deposition of the underlying Skull Creek Shale, the lower Cretaceous sea receded from the area of the Powder River Basin. Subsequently, a widespread drainage system developed and carved its pattern into the Skull Creek Shale. As the lower Cretaceous sea transgressed east, Muddy deltaic sediments buried the previously deposited channel sediments as the sea continued to inundate the basin. Continuous basin fill by deposition of the overlying Mowry Shale resulted in the Muddy reservoir sands being ideally "sandwiched" between two marine hydrocarbon source shales.

In the School Creek Area, a north-south paleodrainage pattern was developed upon the underlying Skull Creek Shale and controlled the distribution of the productive tidal channel and point-bar sands of the lower Muddy formation. Younger upper Muddy marine facies units were then deposited as the Cretaceous sea transgressed east resulting in some well-developed productive marine offshore bar sands within the field area.

In the School Creek Field, the Lower Muddy channel sands have 35 well completions with an average of 11 net feet of pay per well and an average porosity and water saturation of 13.6% and 39%, respectively. Upper Muddy bar sands have 5 well completions with an average of 12 net feet of pay per well and an average porosity and water saturation of 22% and 14%, respectively. Production has also been established in secondary objectives, which include the Sanchey, Turner, and Dakota formations. These wells are not included in this study.

Figure 1 is a plat showing the well locations, their relationship to the Channel Sand and Bar Sand and the three wells from which PVT samples were taken. Figure 2 is a type log for a School Creek Field Muddy formation completion.

The School Creek Field was discovered in 1980 when the Matheson E-1 well was drilled to 10,000 feet and completed in the Muddy formation. The initial reservoir pressure was approximately 3700 - 3600 psi. Basic fluid properties are given from three different PVT studies in Table 2 and Figure 3. Two quite different fluid samples were obtained in the Channel Sand: the Federal EE-1 sample with a bubble point pressure of 3400 psi, GOR of 1557 SCF/BBL and the Matheson E-1 sample with a bubble point pressure of 2705 psi, GOR of 736 SCF/BBL. Based on reported initial producing gas-oil ratios, the Federal EE-1 sample was used to represent wells in the southern portion of the field while the Matheson E-1 sample was used for wells in the northern portion of the field. The Federal J-1 sample was only used to represent the five Bar Sand well completions. Its bubble point pressure was 2838 psi with a gas-oil ratio of 1189 SCF/BBL.

Basic Decline Analysis Equations

The Arps\(^1\) empirical decline equations that can be used for analysis and forecasting future production when depletion is clearly indicated are, for \(b > 0\)

\[
q(t) = \frac{q_i}{[1 + bD_i t]^{1/b}}
\]

and for \(b = 0\) (exponential)

\[
q(t) = \frac{q_i}{e^{D_i t}}
\]

where the limits of \(b\) are between 0 and 1.

For type curve analysis

\[
q_{Dd} = \frac{q(t)}{q_i}
\]

and

\[
t_{Dd} = D_i t
\]

From log-log type curve matching, the match of the rate-time data yields \(b\), \(t\) - \(t_{Dd}\), and \(q(t)\) - \(q_{Dd}\). From these values \(q_i\) and \(D_i\) are evaluated and can then be used in the predictive equations 1 or 2 above to forecast future production and to obtain ultimate recoverable reserves.

As given in reference 3, we can also evaluate the productivity factor from \(q(t)\) - \(q_{Dd}\) match point, the same match point as would be used with the above Arps equations.
where \( r' \) is the effective wellbore radius incorporating the skin term, \( r' = r_w e^{-s} \).

The skin term can also include the effect of a shape factor \( C_s \). See reference 7. If \( r'/r_w' \) can be defined from a match of early transient data, we could then evaluate \( k \) and \( s \) of the well.

To evaluate pore volume \( V_p \), from the match point, we have

\[
V_p = \frac{r' e^2 h_\phi}{(\mu c_\ell) \left( \frac{p_R}{p} - p_{wf} \right)} \cdot \frac{t}{q_D t} \cdot \frac{q(t)}{q_D t} \tag{6}
\]

which gives the pore volume at the start of the decline analysis.

In the above equations, \( \frac{r'_e}{r'_w} \) is normally evaluated at average pressure \( \frac{p_R + p_{wf}}{2} \) while \( \mu c_\ell \) is evaluated at reservoir shut-in pressure \( p_R \).

In terms of an oil pseudo pressure, \( m(p)_{oil} \), equations 5 and 6 can be written as

\[
\frac{kh}{\ln \left( \frac{r'_e}{r'_w} \right)} = \frac{141.2 (\mu b) p}{\mu c_\ell} \cdot \frac{q(t)}{q_D t} \tag{7}
\]

and

\[
V_p = \frac{1}{(\mu c_\ell)} \left( \frac{m(p_R)}{p} - m(p_{wf}) \right) \cdot \frac{t}{q_D t} \cdot \frac{q(t)}{q_D t} \tag{8}
\]

Using a simple, practical engineering \( m(p)_{oil} \) defined from inflow performance relationships, sufficient for decline curve analysis, (see Appendix), we would have for \( p_R \leq p_b \) (bubble point pressure)

\[
\frac{kh}{\ln \left( \frac{r'_e}{r'_w} \right)} = \frac{141.2 (\mu b) p}{\mu c_\ell} \cdot \frac{q(t)}{q_D t} \tag{9}
\]

and

\[
V_p = \frac{2^p_R}{(\mu c_\ell)} \cdot \frac{q(t)}{q_D t} \tag{10}
\]

Note that \( \mu b \) is now evaluated at reservoir shut-in pressure, \( p_R \), as is \( \mu c_\ell \), which then allows cancellation of the viscosity terms in equation 10.

For cases where \( p_{wf} < p_b \) and \( p_R > p_b \), as is the case for most of the School Creek Field wells in this study, the productivity factor is evaluated from

\[
\frac{kh}{\ln \left( \frac{r'_e}{r'_w} \right)} = \frac{141.2 (\mu b) p}{p_R} \cdot \frac{q(t)}{q_D t} \tag{11}
\]

and

\[
V_p = \frac{(\mu c_\ell)}{p_R} \left( \frac{m(p_R)}{p} - m(p_{wf}) \right) \cdot \frac{t}{q_D t} \cdot \frac{q(t)}{q_D t} \tag{12}
\]

Equations 11 and 12 reduce to a simple \( \Delta p^2 \) form when \( p_R \leq p_b \) (see for example equation A-9 in the Appendix).

To calculate a drainage radius from the pore volume, we have

\[
\frac{r' e = \sqrt{V_p x 5.615}}{\pi h_\phi} \tag{13}
\]

and oil in place at the start of the decline analysis is

\[
V_p (1 - s_w) \tag{14}
\]

OIP = \[ \frac{(s)}{p_R} \]

Finally, the original oil in place is determined from

\[ OOIP = OIP + N_p \tag{15} \]

where \( N_p \) is the cumulative production to the start of the decline analysis.

Changes in Backpressure

Since many of the wells in the School Creek Field were evaluated under flowing conditions with more than one change in backpressure occurring, we have extended the single backpressure change superposition equation given in reference 2. Expressed in terms of \( m(p)_{oil} \), for simplicity, we have
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\[ q(t) = \frac{kh \left[ m \left( \frac{p_R}{r_w} \right) - m(p_{wf1}) \right]}{141.2 \left[ n \left( \frac{r_e}{r_w} \right) \right]^{-1}} \left\{ q_{dd} \left( t_{dd} \right) \right\} \]

\[ + \frac{m(p_{wf1}) - m(p_{wf2})}{m(p_R) - m(p_{wf1})} q_{dd}(t_{dd} - t_{dd1}) + \frac{m(p_{wf2}) - m(p_{wf3})}{m(p_R) - m(p_{wf1})} q_{dd}(t_{dd} - t_{dd2}) + \ldots + \frac{m(p_{wf_{n-1}}) - m(p_{wf_n})}{m(p_R) - m(p_{wf1})} q_{dd}(t_{dd} - t_{dd_{n-1}}) \]

The rate change \( \Delta q \) for any backpressure change is a constant fraction of the initial rate at the same initial transient time period, as the rate change retraces the original \( q_{dd} \) curve. The same value of the decline exponent \( b \) is used for all rate change superposition calculations.

\[ \Delta q_1 = q_2 = \frac{q_1}{m(p_R) - m(p_{wf1})} \left[ m(p_{wf1}) - m(p_{wf2}) \right] \ldots (17) \]

and \( \Delta q_2 = q_3 = q_1 \left[ m(p_{wf2}) - m(p_{wf3}) \right] \ldots (18) \)

Note that the \( q_1 / [m(p_R) - m(p_{wf1})] \) is the initial productivity index in BOPD/psi or BOPD/psi², whichever is appropriate, times a \( \Delta p \) or \( \Delta(p^2) \) term for successive flowing pressure changes.

For the more general expression used in this study for pressure above and below the bubble point pressure

\[ \Delta q_1 = q_2 = \frac{q_1}{\Delta m(p)_1} \left[ \frac{p_{wf1}^2 - p_{wf2}^2}{2p_b} \right] \ldots (19) \]

and

\[ \Delta q_2 = q_3 = \frac{q_1}{\Delta m(p)_1} \left[ \frac{p_{wf2}^2 - p_{wf3}^2}{2p_b} \right] \ldots (20) \]

where \( \Delta m(p)_1 = \left( \frac{p_R - p_b}{p_b} \right) \left( \frac{p_{wf1}^2 - p_{wf2}^2}{2p_b} \right) \ldots (21) \)

If and when \( p_R \leq p_b \) the expression reduces to the \( \Delta(p^2) \) form. Similarly when \( p_{wf} > p_b \) the \( \Delta p \) form is obtained. The \( \Delta p \) form would be appropriate for use with decline exponent values of \( b = 0 \) and \( \Delta p^2 \) form for \( b \) values greater than zero. For \( \Delta(p^2) \), \( p_R \leq p_b \), the first backpressure change relationship becomes

\[ \Delta q_1 = q_2 = \frac{q_1}{(p_{wf1}^2 - p_{wf2}^2)} \left( p_{wf1} - p_{wf2} \right) \ldots (22) \]

For \( \Delta p \), \( p_{wf} > p_b \), the first backpressure change relationship becomes

\[ \Delta q_1 = q_2 = \frac{q_1}{(p_R^2 - p_{wf}^2)} \left( p_{wf1} - p_{wf2} \right) \ldots (23) \]

Successive rate changes would be handled as shown in the previously given equations.

One should note that if \( \mu \beta \) were correctly evaluated from \( m(p)_{oil} \) using the inflow performance relationship discussed in the Appendix, all the decline curve analysis could be done directly in pressure terms i.e.

\[ \mu \beta = \frac{p_R - p_{wf}}{m(p_R) - m(p_{wf})} \ldots (24) \]

A detailed example illustrating two backpressure changes is given for the Federal A-1 well, Figures 9 and 10 and Tables 9 and 9A. The example is carried out using the type curve match point and the basic Arps form of the decline equation. The procedure is quite simple using the concept of superposition given by equation 16.

A convenient equation³ that can be used for calculating the total \( \Delta q \) as a result of \( n \) pressure changes is, for a \( \Delta p \) case,

\[ p_{wf_n} = p_{wf_1} - \frac{\left( p_R - p_{wf_1} \right) \left[ \Delta q_1 + \Delta q_2 + \ldots + \Delta q_n \right]}{q_1} \ldots (25) \]
for \( m(p) = 1 \)

\[
p_{wf} = \sqrt{p_{wf_1}^2 - \left( \frac{2p_R - p_{wf_2} + p_{wf_1}}{2} \right)^2 (\alpha_1 + \alpha_2 + \ldots + \alpha_n)}
\]

The \( \alpha \) values are all specifically defined at a common point in time with respect to the initial rate \( q_i \); 1 day or 1 month, for example. A one month time period is used in this study. The Federal A-1 example illustrates this point. (See Figure 9).

One can also back calculate intermediate flowing pressures and rate changes \( \alpha \) while performance matching knowing the initial flowing pressure and rate, and the final flowing pressure. This also will be discussed with the Federal A-1 example.

**METHOD OF DECLINE ANALYSIS**

**Log-Log Data Plots**

The first step in approaching the rate-time log-log analysis in the study of the School Creek Field was to make a log-log plot of all the rate-time data for each well. We next examined each well's plot to find when it actually started on decline. The rate-time data was then reinitialized at the point of decline to \( t = 0 \) and a new log-log plot for each well was prepared. We have thus eliminated the constant rate or excess capacity time period which actually represents the constant rate solution instead of the constant wellbore pressure solution.

For log-log type curve analysis, we can't do decline analysis until the well is actually on decline.

Based on the assumption that each well was draining its 160 acre spacing and that all wells had been equally stimulated — i.e. \( r_e^\infty \) would then be the same for each well, a School Creek Field Type Curve was constructed by overlaying each well's log-log curve, with the axis all kept parallel, until a single curve was obtained. Figure 5 represents this attempt to obtain a total field type curve using data from 19 wells that exhibited a clear decline in their data. The long apparent transient period demonstrated by wells D-1, BA-1, and K-3. If this field type curve were valid, we would have a simple and quick method of preparing an oil production forecast and of determining ultimate recoverable reserves for these wells and the remaining completions. We would take the reinitialized log-log plot for each well, find the best match on the field type curve, and draw a line thru the data down the depletion stem of \( b = 0.30 \). Future rates would be read directly from the real time plot. Ultimate recovery would then be a summation of forecasted rates plus the cumulative production to the start of decline, plus any additional production as a result of placing the well on pump, where applicable.

To determine if the apparent transient stem was real, wells D-1, BA-1, and K-3 were all evaluated for \( k \) and skin \( s \) from a log-log type curve match on the constant wellbore pressure solution (Figures 2 or 5 of reference 3). The evaluation of the match points lead to unassignable values of permeability and more specifically skins for all three wells. None of the wells were massively hydraulically fractured.

It was therefore concluded that the data for these three wells was not really transient and should be placed in the early depletion period of the total field type curve. Figure 6 is our final School Creek Field Type Curve that does not exhibit a long transient stem. The field type curve is primarily a depletion type curve with a \( b = 0.30 \). We will later discuss the \( b = 0.30 \) selected for this study. Blind matching of log-log data to a type curve and extrapolation can sometimes lead to erroneous production forecasts. An evaluation of the match points to obtain reservoir variables for all wells being studied should give consistent and reasonable numbers when compared with each other thus confirming the validity of the forecast and the ultimate reserves numbers developed. The elimination of the apparent transient stem in this case is a good example of such a checking procedure. The composite type curve, Figure 4 of reference 2, was used for all match point evaluations performed in this study.

**Basic Well and Reservoir Data**

<table>
<thead>
<tr>
<th>Well</th>
<th>( k-md )</th>
<th>( s )</th>
</tr>
</thead>
<tbody>
<tr>
<td>D-1</td>
<td>0.017</td>
<td>-7.6</td>
</tr>
<tr>
<td>BA-1</td>
<td>0.040</td>
<td>-8.2</td>
</tr>
<tr>
<td>K-3</td>
<td>0.024</td>
<td>-8.0</td>
</tr>
</tbody>
</table>

Table 1 lists basic individual well information and the match points obtained from a log-log type curve evaluation for 40 well completions. Three of the wells are commingled. The table lists first production, the start of decline analysis and the cumulative production to the start of the decline analysis. Initially, virtually all wells came on flowing with several on curtailed or restricted production before starting on decline. Many wells, because of early high gas-oil-ratios and gas disposition problems, were shut in for as much as a year before being returned to production. This accounts for the difference in time of as much as one year between first production and start of decline, with little cumulative production for some wells during this interval.

Reservoir shut-in pressures, \( q_p \), were generally assumed to be close to the original pressure of approximately 3600 psi except in a few cases where bottomhole pressure surveys were available to indicate otherwise. Flowing pressures were estimated from general pressure surveys conducted on 10 wells in late 1982 and early 1983. Fluid levels shot on pumping wells indicated a minimum bottomhole flowing pressure of approximately 100 psi.

Porosity, thickness and water saturation for each well were furnished by a log analyst. Figure 4 is a permeability-porosity plot developed from of plug samples taken on four wells in the field. The core porosities, in general, are significantly less than the average values determined from log analysis. This will be discussed further under calculated \( r_e \) values.

The final four columns of the table list the match points obtained from the log-log type curve analysis for each of the well completions in terms of \( q_p \) and \( q(t) \) - \( q_{pd} \) obtained using the composite type curve (Figure 4 of reference 2) and a decline exponent \( b = 0.30 \).
PVT Data

PVT properties required for evaluation of reservoir variables from the type curve match points are presented in Table 2 and also Figure 3. These are \( \mu, p \) and \( C_f \), all evaluated at reservoir shut-in pressure, \( p_R \). The total compressibility term, \( C_t \), was calculated using a water compressibility, \( C_w \), of 3 \( \times 10^{-6} \) psi\(^{-1}\) and pore volume compressibility, \( C_f \), obtained from Hall's\(^1\) correlation. The product \( \mu B \) was "mechanically" evaluated at the average pressure \( (p_R + p_wf) / 2 \).

Initially only two PVT samples were available for this study, the Federal EE-1 bottomhole sample to represent Channel Sand completions and the Federal J-1 bottomhole sample to represent Bar Sand completions. The Matheson E-1 PVT surface recombined sample became available only after our initial studies were virtually complete. This sample, because of the vastly different gas-oil-ratio (763 SCF/B versus 1557 SCF/B for the Federal EE-1 well) and because of being a surface recombined sample, had been labeled an unrepresentative sample. Inspection of initial GORs plotted for each well and a gas-oil-ratio versus fractional recovery curve, based on original oil in place developed from the match point evaluations, clearly suggested that the Matheson E-1 sample was valid. The final summary of the evaluation of reservoir variables from type curve analysis was made using the Federal EE-1 PVT data for all wells south of and including wells LL-1, H-1 and R-3. See Figure 1 and Tables 3 and 4. For the northern of these wells we used the PVT data from the Matheson E-1 well sample.

Because the study had been virtually completed when the Matheson E-1 sample results became available, we have included the results of all channel sand wells evaluated using both fluid samples. Basic patterns of evaluation results remained essentially the same between the northern and southern wells, i.e., higher percentage recoveries for the southern wells than the northern wells since their actual rate-time performance was based on the real fluid present, not what we selected to use for the final evaluation summary. The more undersaturated a well was, the less recovery would be obtained as compared with a well with a fluid saturated at its initial shut-in pressure, all else being equal. Tables 5, 6, 7, and 8 summarize the results of the match point evaluations based on \( (p_R - p_wf)/(\mu B) \) and m(p)oil evaluation.

Calculated Results From Decline Curve Analysis

The final results of the type curve evaluation in terms of calculated reservoir variables are presented in Tables 3 and 4; the wells have been arranged on the basis of PVT areas. An m(p)oil evaluation was used for all results given in Table 3 and a \( (p_R - p_wf)/(\mu B) \) evaluation for all values in Table 4.

Pore Volume (\( V_p \))

The pore volume calculations are based on equations 6 and 12, where

\[
V_p = \frac{(\mu B)}{(uc_t)} \left( \frac{(p_R - p_wf)}{p_R} \right) t_D d q_D d \ldots (6)
\]

\[
V_p = \frac{(\mu B)^2}{(ct)^2} \left( \frac{(p_R - p_wf)}{p_R} \right) t_D d q_D d \ldots (12)
\]

Equation 6 would most certainly apply to reservoirs where the single phase liquid solution is applicable, i.e., where the decline curve exponent \( b = 0 \). The introduction of the \( \mu B \) term evaluated at \( (p_R + p_wf) / 2 \) with the \( \Delta p \) form is simply an attempt to account for solution-gas drive or two phase flow behavior. A rigorously derived \( \mu B \) from m(p) concepts, as discussed previously, would be the approach to make equation 6 and 12 equivalent.

For solution gas drive reservoirs, reference 2 demonstrates that the \( \Delta (p^2) \) form of IPR (oil well backpressure curve with \( n = 1.0 \)) used with a non-linear \( p_R \) versus \( N_p \) material balance relationship produces a decline exponent \( b = 0.33 \). Levine and Prats\(^4\), in their simulation study of a solution gas drive reservoir producing under a constant wellbore pressure condition, presented a \( \log q_D = \log t_D \) type curve. (See their Figure 11.) The depletion stem of their type curve basically fits a decline exponent \( b \approx 0.33 \). Figure 7 illustrates one of several wells in the School Creek Field that exhibited rate-time data in a sufficient stage of decline to help us establish a single decline exponent \( b \approx 0.30 \). All our decline curve analysis and rate predictions were based on matching and forecasting on \( b = 0.30 \) for all wells. All forecasts for this study were done by graphical projection.

Figure 8 is a plot of percent recovery versus bottomhole flowing pressure for the Federal A-1 well. Using equations 6 and 12, the bottomhole flowing pressure was varied between 1600 psi to 100 psi and the pore volume \( V_p \) and OOIIP calculated. Ultimate recovery was fixed at 96,000 BO for both \( \Delta p/\mu B \) and \( m(p)_{oil} \) cases to arrive at a percent recovery. Note the lack of sensitivity in percentage recovery for the \( m(p)_{oil} \) case with the variation of bottomhole flowing pressure. Since the \( m(p)_{oil} \) case is effectively a difference in pressures squared effect, we do not see a proportional increase in rate with drawdown as in the \( \mu B \) case even though \( \mu B \) was evaluated at each flowing pressure. This is virtually identical with the effect found for gas wells. The precise determination of flowing pressure, \( p_wf \), may not then greatly affect our final results.

Oil in Place

Oil in place is calculated directly from \( V_p \) using equation 14.
The calculated oil in place is at the start of decline which, when added to the cumulative production up to the start of the decline analysis, yields the original oil in place, OOIP, equation 15. The original oil in place is later used to calculate fractional oil recoveries, Table 10, and GOR versus fractional recovery, in an attempt to help identify or confirm different fluid properties used in the field analysis and also to possibly identify different rock types.

Calculated Drainage Radius \( r_e \)

A "calculated" drainage radius is determined from \( V_p \) with equation 13

\[
 r_e = \sqrt{\frac{V_p \times 5.615}{\pi h \phi}} \quad \text{..................(13)}
\]

The calculated value of \( r_e \) is not only a function of pore volume \( V_p \) determined from the type curve analysis match point but also of porosity \( \phi \) and thickness \( h \). In this type of reservoir, with indicated thin "dirty" sands and possible limited areal extent, the value of average \( h \) used as determined from the logs may be too high. This would result in a calculated \( r_e \) value in some cases much less than \( r_e = 1490 \) feet for 160 acres. Also, very few of the core sample plugs obtained from wells in the field (see Figure 4) appear to approach the average porosity values reported from the log analysis listed on Table 1. If one were to build a simulation model of the School Creek Field, outlined in Figure 1, based on the log derived values of \( \phi \), \( h \), and 160 acre spacing for each well, we would have to cut the pore volume to match the type curve analysis derived reservoir variables, specifically oil in place, that have already been history matched to the rate-time decline data.

To come up with calculated values of \( r_e \) approaching the 160 acre field spacing, the \( \phi h \) product would have to be decreased. Otherwise, the rather tenuous conclusion that many wells are not draining the existing spacing could lead to a consideration of infill drilling.

Productivity Factor (P.F.)

The productivity factors for each well are calculated from equations 5 and 11,

\[
P.F. = \frac{kh}{\ln\left(\frac{r_e}{r_w}\right) - 1} = \frac{141.2 (\mu b)}{\text{P.R.}} \cdot \frac{q(t)}{q_{bd}} \quad \text{...........(5)}
\]

where \((\mu b)\) is evaluated at average pressure \((P_R + P_{wf})/2\)

and

\[
 P.F. = \frac{141.2 (\mu b)}{R} \cdot \frac{q(t)}{q_{bd}} \quad \text{...........(11)}
\]

Since there is a lack of early time transient rate data to sufficiently define an \( r_e/r_w \) stem, unique values of permeability and skin cannot be calculated for each well. We know that all completions were initially stimulated. The core data indicates an arithmetic average permeability of 0.650 md and a geometric average of 0.195 md, with a range of 0.2 md to 7 md. We also had one buildup test conducted on the KK-1 well where the final flowing pressure prior to shut-in was above the bubble point pressure. The analysis yielded a value of \( k = 2.5 \) md and \( s = -3.4 \).

A range of values of skin from 0 to -4 was selected to evaluate permeabilities for each well. When we fix \( r_w' \) on the basis of skin, \( r_w' = r_e e^s \), and having previously calculated \( r_e \) from the pore volume calculation we can then calculate \( kh \) and \( k \) from equations 5 and 11.

The ranges of values of \( k \) listed on tables 3 and 4 for various values of skin are surprisingly narrow within a given table and even between the two methods of calculation used. It should be pointed out that the values of permeability and skin calculated from the decline curve analysis are those at the start of the decline analysis.

If a good correlation from the core derived \( \phi - k \) plot had been obtained and if log derived average porosities were considered reasonably reliable, we could have used it to determine \( k \) and then its corresponding skin from the tables for each well. Based solely on the KK-1 build-up analysis results and the fact that all wells were stimulated, one could also select the -3 skin columns on Table 3 or 4 to arrive at specific values of permeability at the start of decline for each well. There are no unreasonable values of permeabilities listed on either table. Nearly all lie within the range of the core permeabilities shown on Figure 4. Values of permeabilities in the 10s or 100s md on any well would, of course, be suspect.

Example of Effect of Backpressure Change on Recovery and Decline

The equations to calculate the change in producing rates with backpressure changes have been given previously as equations 16 - 26. The Federal A-1

\[
 s = \frac{P_R - P_w f (2 - s)}{2 P_w f} \quad \text{...........(26)}
\]
well produced against three different flowing pressures that resulted in two rate changes. Figure 9 is a log-log plot of the rate-time data with the solid line through the points calculated from the type curve match points used with the Arps hyperbolic decline equation. Only the first and last flowing pressures of 1400 psi and 100 psi, respectively, were known. Equation 25, solved in terms of $A_q$ total with $P_{wf3} = 100$ psi yielded a total $A_q = 274$ BOPM. A trial and error calculation was then made varying $A_{q1}$ until a best fit of both rate changes was obtained. This resulted in a $P_{wf2} = 1069$ psi.

Tables 9 and 9-A illustrate in detail the method of developing a forecast with two backpressure changes using the $m(p)_{oil}$ approach. Note specifically that since the rate-time decline is undergoing depletion, the Arps equation is used for all calculations. One does not have to deal with the reservoir variables, $k_h$, $s$, $n$, obtained from the match evaluations. This, however, would not be the case for a transient situation. Theoretically, the rates for the first few months should be calculated at the mid-point of the time interval, i.e., 0.5, 1.5, 2.5, to represent average monthly production rates. For simplicity of presentation of the superposition example, the rates have been evaluated at full month time intervals.

Table 9-A column 2 lists the rates for the initial flowing pressure, $P_{wf1}$, calculated from Arps' equation with $b = 0.3$, $q_1 = 4545.5$ BOPM and $D_t = 0.212$ mo$^{-1}$. The rate change as a result of a choke change to $P_{wf2} = 1069$ psi is listed in column 3. It is simply a constant fraction of the initial decline rates. The second backpressure change, when the well was placed on pump to $P_{wf3} = 100$ psi, is treated similarly. For superposition, columns 3 and 4 are retabulated at a time 1 month past the actual time of the pressure change. Total rate is the sum of columns 2, 5, and 6. Adding the cumulative production to the start of decline analysis (2633 BO), we have

$$N_{Ultimate, BO} = \frac{\Delta m(p)_{oil}}{\Delta(p)}$$

No backpressure change 30,347 30,347
First backpressure change 32,668 34,668
Second backpressure change 35,858 47,226

The $\Delta p$ numbers in the above table were generated for comparison by recalculating $\Delta q_1$ and $\Delta q_2$ on the basis of a $\Delta p$ superposition using equation 23. From this approach, a procedure using actual production data (and its projected rates for a known initial flowing pressure) could be developed to determine the effect of a backpressure change on ultimate recovery, as follows.

Determine $N_p$ at $P_{wf1}$ to $t = T$, where $T$ = total time of rate-time forecast,

$$T - t = P_{wf2}$$

then $\Delta N_{p1} = \frac{\Delta q_1}{q_1} \cdot \sum_{t = 1}^{T - t} q_{actual}$

and $\Delta N_{p2} = \frac{\Delta q_2}{q_1} \cdot \sum_{t = 1}^{T - t} q_{actual}$

where $q_{actual}$ may also be actual production plus that projected for the initial flowing pressure, $P_{wf1}$.

**Ultimate Recoverable**

$$N_p + \Delta N_{p1} + \Delta N_{p2}$$

Similarly, actual early time production rates instead of calculated values can be used to generate the rate-time superposition as illustrated in Table 9-A. This in essence would have the effect of including a downtime if any early time rate variations were due to downtime.

Figure 10 illustrates one more point about backpressure changes with regard to the decline exponent. As has previously pointed out in references 2 and 3, the sum of two forecasts, both having the same value of decline exponent $b$, will rarely result in a total forecast having the same decline exponent. In general, the total forecast decline exponent will be larger. Reinitializing the rate-time data after the second backpressure change which also has $b = 0.3$ resulted in a decline exponent $b = 0.40$.

Finally, unless all wells are placed on pump at the same time, a backpressure change can cause a well's drainage radius to increase with respect to offset wells. The given superposition example implicitly assumes that $r_e$ remains constant.

**Commingled Wells**

There are three wells in the School Creek Field where Bar Sand production and Channel Sand production are presently commingled. Figures 11 and 12 for the Federal K-1 well illustrate the method of analysis used to evaluate these wells. A difference curve was developed between the forecast rates of the Channel Sand production only and the commingled production which came on production later. Separate forecasts were then made and added together.

**Summary of School Creek Field 00IP and Ultimate Recovery**

Table 10 summarizes the results of the calculated original oil in place and ultimate recovery forecast for each well based on an $m(p)_{oil}$ and a $\Delta p/\mu$ evaluation. The superposition of rates as a result of backpressure changes using equations 19 and 23 have also been included where appropriate.

Channel Sand completion results are divided into the northern and southern areas of the field based on the two PVT samples discussed previously. Both evaluation methods indicate a much higher percentage recovery for wells in the northern portion of the field as compared with wells in the southern portion. Wells in the southern portion have percentage recoveries near twice those of wells to the north. This would be consistent solely on the basis of the differences in bubble point pressures between the
two fluid samples. Values of percentage recoveries are always lower for the m(p) oil evaluation method. With regard to the additional recoverable reserves that could possibly be obtained by placing all wells on pump to a final bottomhole flowing pressure of 100 psi, the following table summarizes those results. (Nearly half of the wells were initially at or near 100 psi bottomhole flowing pressure at the start of decline.)

<table>
<thead>
<tr>
<th>Reserves for</th>
<th>Increase of m(p) oil</th>
<th>Increase of Δp/Δt</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Flowing Pressure of 100 psi to Pwf</td>
<td>Reserves</td>
<td>Reserves</td>
</tr>
<tr>
<td>STB</td>
<td>STB</td>
<td>%</td>
</tr>
<tr>
<td>Northern Wells</td>
<td>223,900</td>
<td>15,594</td>
</tr>
<tr>
<td>Southern Wells</td>
<td>312,105</td>
<td>19,220</td>
</tr>
<tr>
<td>Total Field</td>
<td>819,484</td>
<td>68,354</td>
</tr>
</tbody>
</table>

If, in fact, the inflow performance relationship based on Δp^2 applies, the percentage increase as a result of placing all wells on pump to a final flowing pressure of 100 psi would be approximately 8% or 68,000 BO. If the inflow performance relationship were to follow a Δp (PI) behavior, the anticipated increase in reserves would be 28% or 230,000 BO. Perhaps the real increase in reserves due to lowering the final bottomhole flowing pressure lies somewhere between these two limits.

**Individual Well Gas-Oil-Ratio Performance**

Figures 13 thru 16 reflect gas-oil-ratio performance of individual wells in the field based on knowing the recovery factor in terms of each well's actual cumulative production divided by the OOIP calculation from the m(p) oil evaluation. Either method of calculating OOIP should show similar trends. Gas and oil rates are metered separately for each well and are not based on allocation from tests.

Figures 13 and 14 are on an expanded gas-oil-ratio scale in an attempt to help identify rock types in each area of the field. If one assumes the fluids are the same for each area, three different rock types and/or initial water saturations are possibly indicated in the southern portion of the field.

Figures 15 and 16, prepared on a scale where the entire gas-oil-ratio performance of each well can be shown clearly, indicate two different fluids, based mainly on the wells’ peak gas-oil-ratio alone which is not a function of the method of calculating an OOIP number. Note that the gas-oil-ratio has turned over on several wells. The peak gas-oil-ratios for the northern wells is generally much lower than those of the southern wells. These gas-oil-ratio curves could be used in developing a gas forecast to go with the oil rate forecast developed from the decline curve analysis.

**CONCLUSIONS**

Original oil in place values can be calculated from rate-time analysis for individual wells and can also be used with reserves projections developed from the decline analysis to obtain fractional recoveries for each well in a field. These fractional recovery numbers should be reasonable, considering the fluid type and the permeability of the reservoir.

Each well's evaluation of the reservoir variables k, s (skin), OOIP and fractional recovery, obtained from individual well rate-time decline analysis, should give consistent and reasonable numbers when compared with other wells in the field. A single well analysis can give results that are not recognized as being invalid unless compared with other wells in the field.

Failure to consider a future lowering of a well's bottomhole pressure from that causing a well's initial rate-time decline can result in underestimating ultimate recoverable reserves.

A method of treating future backpressure changes based on the superposition principle and an oil well inflow performance relationship is easily applied to decline curve analysis. An oil well inflow performance relationship can be utilized over an entire production forecast, not only at an instant in time.

**NOMENCLATURE**

- b = reciprocal of decline curve exponent (1/b)
- β = formation volume factor, res vol/surface vol
- C_F = effective rock compressibility, psi⁻¹
- C_T = total compressibility, psi⁻¹
- C_W = water compressibility, psi⁻¹
- D_i = initial decline rate, t⁻¹
- e = natural logarithm base 2.71828
- h = thickness, ft
- k = effective permeability, md
- k_r_o = relative permeability to oil, fraction
- m(p) oil = oil pseudo pressure, psi/cp
- n = exponent of backpressure curve
- OIP = oil in place at start of decline analysis, STB
- OOIP = original oil in place, STB
- P_b = bubble point pressure, psia
- P_PR = reservoir shut-in pressure, at start of decline, psia
- P_wf = bottomhole flowing pressure, psia
- q_D = decline curve dimensionless rate
- q(t) = surface rate of flow at time t
- r_e = external boundary radius, ft
- r_w = wellbore radius, ft
- r_w_r = effective wellbore radius, ft
- s = skin factor, dimensionless
- S_w = water saturation
- t = time, mo.
- t_D = decline curve dimensionless time
- t_f = total time of forecast, mo.
- V_p = reservoir pore volume, ft³
- μ = viscosity, cp
- Φ = porosity, fraction of bulk volume

NOMENCLATURE
ACKNOWLEDGEMENTS

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REFERENCES


APPENDIX

Oil Pseudo Pressure, m(p)oil For Decline Curve Analysis

Reference 10) introduced the concept of a pseudopressure m(p) for oil well drawdown tests similar to that now commonly used for gas wells. It was presented along with a general inflow performance relationship developed from multi-point test data of some 40 oil well tests.

A general inflow performance equation for decline analysis that treats flow both above and below the bubble point pressure for an undersaturated oil well assuming no non-Darcy flow component is

\[ q_o = J^* \left( \frac{R_p}{R_b} - p_b \right) + J^* \left( p_b^2 - p_{wf}^2 \right) \] .......(A-1)

where \( J^* = \frac{kh}{141.2 \left( \ln \left( \frac{r_e}{r_w} \right) - \frac{1}{2} \right) \left( \frac{\mu_o \beta_o}{\mu_o \beta_o + \mu_o \beta_o} \right)} \) .......(A-2)

and \( J^* = \frac{J^* (\mu_o \beta_o)}{p_b \frac{a_2}{R_p} \frac{p_b}{2}} \) .......(A-3)

Assuming \((\mu_o \beta_o)\) is a constant value above the bubble point pressure equal to \((\mu_o \beta_o)_{Bb}\) (the basis for the constant PI assumption for flow above the bubble point pressure, \(P_b\)) then (See also Appendix of reference 10)

\[ a_2 = \frac{1}{p_b (\mu_o \beta_o)_{Bb}} \] .......(A-4)

For \(1/(\mu_o \beta_o)\) to go through a zero intercept on drawdown, we are really looking at a \(1/(\mu_o \beta_o)\), \(P_{wf}\) curve. This then would reproduce field data log-log IPR curves with \(n = 1.00\) and also Vogel’s [11], Figure 7, a computer generated IPR. (Figure 17 in this paper.)
Thus
\[ J^* = \frac{J^*}{2p_b (\mu_0 \beta_0 p_b - P_b)} = \frac{J^*}{2p_b} \] .......(A-5)

Substituting equation (A-5) into (A-1) we obtain the final form of the single phase and two phase IPR equation
\[ q_o = J^* \left[ \frac{\left( P_R - P_b \right) + \left( P_b^2 - P_w^2 \right)}{2p_b} \right] \] .......(A-6)

or in terms of reservoir variables, with \( k_{r0} = 1 \) at start of decline analysis
\[ q_o = \frac{kh}{141.2 \left[ \ln \left( \frac{r_e}{r_w} \right) - \frac{1}{2} \right]} \cdot \frac{1}{(\mu_0 \beta_0) - \frac{P_R}{2p_b}} \left[ \left( P_R - P_b \right) + \left( P_b^2 - P_w^2 \right) \right] \] .......(A-7)

or in terms of \( m(p)_{oil} \)
\[ q_o = \frac{kh}{141.2 \left[ \ln \left( \frac{r_e}{r_w} \right) - \frac{1}{2} \right]} \cdot \frac{1}{(\mu_0 \beta_0) - \frac{P_R}{2p_b}} \left[ m(p_R) - m(p_{wf}) \right] \] .......(A-8)

For the case of \( P_R < P_b \) we have from equation (A-7)
\[ q_o = \frac{kh}{141.2 \left[ \ln \left( \frac{r_e}{r_w} \right) - \frac{1}{2} \right]} \cdot \frac{1}{(\mu_0 \beta_0) - \frac{P_R}{2p_b}} \cdot \left( P_R^2 - P_w^2 \right) \] .......(A-9)

With \( P_R < P_b \) we can compare the Vogel and the \( \Delta p^2 \) inflow relationship in terms of \( m(p)_{oil} \). We have
\[ \Delta p^2 \text{ form: } m(p)_{oil} = \frac{1}{2p_R} \cdot \left( \frac{k_{r0}}{(\mu_0 \beta_0) - \frac{P_R}{p_R}} \right) \cdot p^2 \] .......(A-10)

The Vogel form would be extremely cumbersome if entered into the constant wellbore pressure solutions as an \( m(p)_{oil} \) expression whereas the \( \Delta p^2 \) form results in a simple expression identical in form to the low pressure gas well backpressure equation. Oil well IPR curves, just as gas well backpressure curves are most applicable to the constant wellbore pressure solution conditions. A comparison of the \( \Delta p^2 \) form of IPR and Vogel's IPR equation (both these forms assume a non-Darcy flow component of zero) can be seen in figure 17. The results shown on Vogel's figure 7 are the only complete set of curves given in his paper with which we could make a comparison of the two methods when using the same match point. Vogel's points of match A thru H were used to develop the comparison. Note from the figure 17 comparison that the \( \Delta p^2 \) form of the equation better fits his computer calculated IPR over the entire range of depletion than his own dimensionless form of the IPR equation. At very low flowing pressures approaching 0 flowing pressure, a region we seldom deal with, the \( \Delta p^2 \) form is slightly less than the simulation run result but still closer than using Vogel's dimensionless equation.

Reference 2 illustrates that when the \( \Delta p^2 \) form of the IPR equation is combined with a non-linear \( p \) versus \( N_p \) relationship for solution gas drive reservoirs, the expected decline curve exponent \( b = 0.333 \). This is practically the same value as that found and used in this study.
### Table 6

**School Creek Field - Calculated Decline Curve Analysis Results Based on Federal E-1 FAT (Channel XAND) and API 10-A Evaluation**

<table>
<thead>
<tr>
<th>Well</th>
<th>Rate</th>
<th>Decline Factor</th>
<th>Slope</th>
<th>Intercept</th>
<th>$t = 0$</th>
<th>$t = 2$</th>
<th>$t = 4$</th>
<th>$t = 8$</th>
<th>$t = 12$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1</td>
<td>1500</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
</tr>
<tr>
<td>B-1</td>
<td>1000</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
</tr>
<tr>
<td>C-1</td>
<td>1500</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
<td>0.20</td>
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</tr>
</tbody>
</table>

### Table 7

**School Creek Field - Calculated Decline Curve Analysis Results Based on Mathews E-1 FAT (Channel XAND) and API 10-B Evaluation**

<table>
<thead>
<tr>
<th>Well</th>
<th>Rate</th>
<th>Decline Factor</th>
<th>Slope</th>
<th>Intercept</th>
<th>$t = 0$</th>
<th>$t = 2$</th>
<th>$t = 4$</th>
<th>$t = 8$</th>
<th>$t = 12$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A-1</td>
<td>1500</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
<td>0.50</td>
</tr>
<tr>
<td>B-1</td>
<td>1000</td>
<td>0.40</td>
<td>0.40</td>
<td>0.40</td>
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<tr>
<td>C-1</td>
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</tr>
</tbody>
</table>
TABLE 9
EXAMPLE OF EFFECT OF BACKPRESSURE CHANGE ON DECLINE AND RECOVERY

FEDERAL A-1

\[ q(t) = \frac{4545.5}{1 + 0.220} \frac{P}{t} \]

\[ 1000 \text{ BOPH} \]

\[ q(t) = \frac{4545.5}{1 + 0.220} \frac{P}{t} \]

\[ t = 1 \text{ mo}; \quad q(t) = 0.220 \]

\[ q(t) = \frac{4545.5}{1 + 0.0636t} \]

First backpressure change 1400 psi to 1069 psi \( t = 11 \text{ months} \)

\[ q(t) = \frac{4545.5}{1 + 0.0636t} \]

\[ t = 1 \text{ mo}; \quad q(t) = 0.220 \]

\[ q(t) = \frac{4545.5}{1 + 0.0636t} \]

Second backpressure change 1069 psi to 100 psi \( t = 16 \text{ months} \)

\[ q(t) = \frac{4545.5}{1 + 0.0636t} \]

\[ t = 1 \text{ mo}; \quad q(t) = 0.220 \]

\[ q(t) = \frac{4545.5}{1 + 0.0636t} \]

TABLE 9-A
EXAMPLE OF EFFECT OF BACKPRESSURE CHANGE ON DECLINE AND RECOVERY

FEDERAL A-1

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>313</td>
<td>343</td>
<td>313</td>
<td>343</td>
</tr>
</tbody>
</table>

\[ t = 12 \text{ mo}; \quad t = 17 \text{ mo} \]

\[ \text{Total Percent Recovery Factor} \times \text{Total Reserves} = \text{Total OIP} \]

SPE 14237
Fig. 1—School Creek field well location map.

Fig. 2—Type log for a Muddy formation completion.

Fig. 3—PVT samples from the School Creek field.

Fig. 4—Porosity-permeability results from core analysis.
Fig. 5—Initial School Creek field log-log type curve.

Fig. 6—Final School Creek field log-log type curve.

Fig. 7—Decline exponent b = 0.30 established from rate-time data.

Fig. 8—Sensitivity of calculated percent recovery and permeability to bottomhole flowing pressure.
Fig. 9—Example of effect of backpressure changes on recovery.

Fig. 10—Effect of backpressure changes on decline exponent, b.

Fig. 11—Rate-time data for a well commingled with another reservoir.
Fig. 12—Decline data for a coninging well established by difference in production.

Fig. 13—Individual well GOR performance, based on $m_{pij}$ calculated OOIP.

Fig. 14—Individual well GOR performance, based on $m_{pij}$ calculated OOIP.
Fig. 15—Individual well peak GOR performance, based on mgt calculated OOIP.

Fig. 16—Individual well peak GOR performance, based on mgt calculated OOIP.

Fig. 17—Comparison of inflow performance equations.