A Novel Approach for the Evaluation of Oil and Gas Well Performances in Multiwell Reservoir Systems
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Abstract
The current methods for estimating Oil- or Gas-In-Place and Reservoir Flow Capacity using dynamic data (pressure and/or rate) assume a single well in a closed system (or single well with constant pressure or prescribed influx at the outer boundary). In many cases a well produces in association with other wells in the same reservoir – and unless all wells are produced at the same constant rate or the same constant bottomhole flowing pressure, non-uniform drainage systems will form during boundary-dominated flow conditions.

The approach presented in this paper accounts for the entire production history of the well and the reservoir and eliminates the influence of well interference effects. This approach provides much better estimates of the in-place fluids in a multiwell system, and the methodology also provides a consistent and straightforward analysis of production data where well interference effects are observed.

This paper also presents the computation of flow capacity and skin factor using the multiwell approach.

Introduction
Analysis of well production data has some advantages over pressure transient analysis in which it is not required to shut-in the well. The data are also available over a long time span, which include transient and boundary dominated flow data. Hence, the complete information may be obtained about the reservoir (permeability, drainage radius, fluid-in-place, and reservoir type) and about the well (skin factor, effective fracture half-length, fracture conductivity, and effective horizontal well length). This type of analysis can be done by decline type curve method. The common practice is to use a single well model with fixed reference boundary (no-flow, constant pressure or prescribe influx). It implies that the well drainage area is constant over time. This may be true if the reservoir is produced only by a single well. Except for a very small field, this unlikely occur in practice.

The change of individual well drainage area in a multiwell reservoir is due to addition of new well during development, infill well, changing well completion, closing/reopening, stimulation, and changing production schedule. The effect of some of these factors on well drainage area is illustrated in Figs. 1 and 2. These figures are generated using a numerical reservoir simulator. Fig. 1a shows pressure distribution when only single well, namely Well A, produces from the reservoir. When a new well, namely Well B, is introduced the drainage area of Well-A changes and in this case decreases due to competing with Well-B. Another scenario is shown by Fig. 2. At the beginning, two wells (Well-A and Well-B) produce oil with the same rate from the reservoir, and after some period of times each well establishes its own drainage area (Fig. 2a). When production rate of Well-B is increase while maintaining the production rate of Well-A, the drainage area of Well-B enlarges and the drainage area of Well-A shrinks.

Those are two basic mechanisms that are responsible for changing well drainage area from which the explanation of the other factors can be derived. The effects of closing/reopening and infill well are similar to adding new well (Fig. 1). While the effects of changing well completion, stimulation, changing production schedules are similar to the effect of changing well production rate (Fig. 2). These phenomena of changing well drainage area cannot be captured properly if a single well model is used to analyze the production data. Hence, the objective of this paper is to develop a multiwell model so that the change of well drainage area in multiwell reservoirs can be properly addressed.

Decline Curve Analysis In A Multiwell Reservoir System
Marhaendrajana et al. presented general solution for the well performance in a bounded multiwell reservoir system:

\[
\frac{P_{D}}{P_{w}} 
= \sum_{i=1}^{n_{well}} \int_{0}^{t_{max}} q_{D,i}(t) \left( \frac{dP_{D,i}(t\Delta t - t)}{d\tau} \right) d\tau + q_{D}(t\Delta t) \gamma_{k,i} \]

The physical model used to develop Eq. 1 is shown in Fig. 3. This model assumes a closed rectangular reservoir with a constant thickness, which is fully penetrated by multiple vertical wells (the well locations are arbitrary). The reservoir is assumed to be homogeneous, and we also assume the single-phase flow of a slightly compressible liquid. The
constant rate solution inside the integral in Eq. 1 is computed at a particular well (well “k”) and includes the effects of each well in the reservoir system.

Furthermore, they showed that a data analysis method can be derived from the multiwell solution, where Eq. 1 can be written as

\[
\frac{q_k(t)}{(p_i - p_{wf}(t))} = \frac{1}{N c_i} \int t_{tot} + f(t) \tag{2}
\]

where

\[
t_{tot,k} = \frac{1}{q_k} \int_0^{\tau_{field}} q_k(\tau) d\tau = N p_{tot}(t) \tag{3}
\]

Although the solution was developed based on a slightly compressible liquid assumption, it had been shown in their works that it can be used for gas, provided the pseudopressure and pseudotime functions are used.

For boundary-dominated flow, Eq. 2 can be written in terms of the dimensionless variables as

\[
p_p = \left[\frac{\tau_{field}}{\tau_{Pp}}\right] \int_0^{\tau_{field}} \frac{p_i}{\mu c_i} dp \tag{4}
\]

\[
\tau_d = \left[\frac{\mu c_i}{\mu c_{pavg}}\right] \int_0^{\tau_{field}} \frac{1}{\mu c_{pavg}} d\tau \tag{5}
\]

and the total material balance pseudotime is expressed as

\[
\tau_{a, tot} = \left[\frac{\mu c_i}{\mu c_{pavg}}\right] \int_0^{\tau_{field}} \frac{q_{g, tot}}{q_{g, well}} d\tau \tag{6}
\]

Since variable \( f(t) \) is constant during boundary dominated flow conditions, this Equation suggests that if we plot \( q_k(t)/(p_i - p_{wf}(t)) \) versus the “total material balance time” function, then we can estimate the original oil-in-place (OOIP) for the entire reservoir using decline type curves. For boundary-dominated flow, Eq. 2 can be written in terms of the dimensionless variables as

\[
q_{Dde} = \frac{1}{t_{Dde} + 1} \tag{7}
\]

where

\[
q_{Dde} = \frac{141.2 B_{oil} \frac{q_k(t)}{Kh} \ln\left[\frac{q_{Dde}/\sqrt{\beta_D}}{2}\right]}{0.00633 \frac{\phi \mu c_i}{A_{pull}} \ln\left[\frac{q_{Dde}/\sqrt{\beta_D}}{2}\right]} \tag{8}
\]

\[
t_{Dde} = \frac{141.2 B_{oil} \frac{q_k(t)}{Kh} \ln\left[\frac{q_{Dde}/\sqrt{\beta_D}}{2}\right]}{0.00633 \frac{\phi \mu c_i}{A_{pull}} \ln\left[\frac{q_{Dde}/\sqrt{\beta_D}}{2}\right]} \tag{9}
\]

This result states that the performance of an individual well in a multiwell system behaves as a single well in a closed system—provided that the total material balance time function is used. Furthermore, this observation implies that the Fetkovich/McCray type curves for a single well—which include both transient and boundary-dominated flow—can also be used to analyze data from a multiwell reservoir system, provided that properly defined dimensionless variables are used (Eqs. 8 and 9).

Type curve matching procedure to analyze production data of a well producing from a multiwell reservoir is as follows:

1. This procedure assumes that we have accurate measured rates and bottomhole flowing pressure (or wellhead pressure). Measurement of average reservoir pressure is not required in this method.
2. Compute total material balance time function for oil wells and total material balance pseudotime function for gas wells.

\[
\tau_{tot} = \frac{N p_{field}}{q_{well}} \tag{10}
\]

for oil wells, and

\[
\tau_{a,tot} = \left[\frac{\mu c_i}{\mu c_{pavg}}\right] \int_0^{\tau_{field}} \frac{q_{g, field}}{q_{g, well}} d\tau \tag{11}
\]

for gas wells.

3. Compute flow rate, flow rate integral and flow rate integral derivative functions.

\[
\frac{q}{\Delta p} = \frac{q}{(p_i - p_{wf})} = \frac{q}{\Delta p} \tag{12}
\]

for oil wells and

\[
\frac{q}{\Delta p} = \frac{q}{(p_{wf} - p_{pavg})} = \frac{q}{\Delta p} \tag{13}
\]

for gas wells.

\[
\frac{q}{\Delta p} = \frac{1}{\tau_{tot}} \int_0^{\tau_{field}} \frac{q}{\Delta p} d\tau \tag{14}
\]

\[
\frac{q}{\Delta p} = -\tau_{tot} \int_0^{\tau_{field}} \frac{d\left[\frac{q}{\Delta p}\right]}{d\tau} \tag{15}
\]

4. Plot \((q/\Delta p), (q/\Delta p)_o, (q/\Delta p)_g\) versus on a scaled log-log grid. Match the data to type curve (Fig. 4). Record the “time” and “rate” axis match points as well as the matched transient stem.

5. Compute oil-in-place or gas-in-place of the field using equations below.

\[
N = \frac{1}{c_i} \left[\frac{\tau_{field}}{t_{Dde,Mp}}\right] \left[\frac{q}{\Delta p}\right]_M \tag{16}
\]

\[
G = \frac{1}{c_i} \left[\frac{\tau_{field}}{t_{Dde,Mp}}\right] \left[\frac{q}{\Delta p}\right]_M \tag{17}
\]

6. Compute the permeability in the vicinity of the well.

\[
k = \frac{141.2 B_{oil} H_{oil} \ln\left[\frac{e h}{\sqrt{\beta_D}}\right]}{0.05} \left[\frac{q}{\Delta p}\right]_M \tag{18}
\]

for oil wells, and

\[
k = \frac{141.2 B_{oil} H_{oil} \ln\left[\frac{e h}{\sqrt{\beta_D}}\right]}{0.05} \left[\frac{q}{\Delta p}\right]_M \tag{19}
\]

So far, we have not presented a way to compute skin factor. For this purpose parameter \(\beta_D\) need to be resolved. Parameter \(\beta_D\) represents a ratio of total field area to well drainage area. Therefore this parameter changes with time and during boundary dominated flow condition the following relation applies (assuming average properties of porosity, permeability and reservoir thickness):

\[
\frac{q}{A} = \frac{q_1}{A_1} = \frac{q_2}{A_2} = \ldots = \frac{q_k}{A_k} = \ldots = \frac{q_n}{A_n} \tag{20}
\]

where:

- \( q \) = total field production
- \( A \) = total field area
- \( q_k \) = well k production \((k=1,2,\ldots,n)\)
- \( A_k \) = well k drainage area \((k=1,2,\ldots,n)\)

Rearranging Eq. 20, drainage area of well k can be computed using Eq 21 as follows:

\[
A_k = A \frac{q_k}{q} \tag{21}
\]

Procedure to compute skin factor from type curve matching is then as follows:
1. Compute area of the field.
\[ A = 5.615 \frac{NB_{gi}}{\phi h(1 - S_{wi})} \] (22)
for oil wells, and
\[ A = 5.615 \frac{GB_{gi}}{\phi h(1 - S_{wi})} \] (23)
for gas wells.
2. Compute well drainage area using Eq. 21.
3. Compute well drainage radius.
\[ r_e = \sqrt{\frac{A}{\pi}} \] (24)
4. Compute effective well radius.
\[ r_{wa} = \left[ \frac{r_e}{\sqrt{\beta_D^2}} \right]_{MP} \] (25)
5. Compute skin factor.
\[ s = -\ln \left( \frac{r_{wa}}{r_w} \right) \] (26)

Field Application
To demonstrate the application of this method to field data, several cases of well performance data from Gas Field X are analyzed. This field has 111 wells (79 producers, 11 injectors, 4 observation wells, and 17 abandoned wells). The layout of the field is shown in Fig. 5 would certainly be considered a multiwell reservoir system.

The X field is a supergiant gas condensate reservoir with a maximum liquid dropout of approximately 1.5% at the dewpoint (although most data suggest that the maximum liquid production should be less than 1%). In our analysis, the variation of fluid properties with pressure is incorporated by the use of pseudopressure and pseudotime. In addition, we use the total (molar) gas rate. Using this procedure we expected to estimate the correct gas-in-place volume for the entire field, as well as correctly estimate the local (per well) effective permeabilities to gas.

We analyzed selected cases of well performance data from the following X field wells:
- Well X-II-01 (X-037)
- Well X-II-02 (X-016)
- Well X-II-03 (X-032)
- Well X-II-04 (X-024)
- Well X-II-05 (X-017)
- Well X-II-06 (X-029)
- Well X-II-07 (X-028)
- Well X-II-08 (X-041)
- Well X-II-09 (X-034)

We discuss in detail the analysis results obtained using the production data from Well X-III-02 (X-015). The production history of Well X-III-02 (X-015) (wellhead pressure and gas rate versus time) is plotted in Fig. 6. The production history includes both wellhead flow rates and flowing wellhead pressure data.

In this example, we use both single well (i.e., single well material balance pseudotime) and our proposed multiwell decline type curve analysis (i.e., total material balance pseudotime) techniques. The decline type curve matches for both the single and multiwell approaches are shown in Fig. 7. Our multiwell analysis approach matches the production data functions (solid symbols) to the type curve very well (we used pseudopressure and pseudotime functions to account for the dependency of fluid properties on pressure).

The single well approach (based only on the rate and pressure data for a single well) fails to match the late time material balance trend, where the boundary-dominated flow data deviate systematically from the type curve (Fig. 7, open symbols). We recognize that this behavior is due to well interference effects caused by competing producing wells, but the single well approach has no mechanism to correct or account for well interference behavior.

Our analysis using the multiwell approach yields an estimate of the OGIP for X field of approximately 19.8 TCF. The estimate of the effective flow capacity (to gas) for this well is 2,791 md-ft, which is based on the match of the early time (transient flow) data.

Figs. 8 and 9 show the log-log plots of the rate/pressure drop and decline type curve match, respectively, for all 11 wells that we considered for our combined analysis. All the curves converge to the unique material balance trend at late time. This region (i.e., the boundary-dominated flow data) will be used to establish an estimate of the total (in-place) gas reservoirs for X field.

The skin factor of each well is shown in Fig 10. From the observation of the skin factor, these 11 wells can be classified into three groups. First group consists of Wells X-015, X-017, X-028, X-034, and X-041. Second group consists of Wells X-016 and X-024. These wells are characterized by skin factor of 0 to -3. The remaining, third group, consists of Wells X-029, X-032, X-035, and X-041. High skin value may be due to successful acid fracturing treatment on these wells. Second group consists of Wells X-016 and X-024. These wells are characterized by skin factor of 0 to -3. The remaining, third group, consists of Wells X-015, X-017, X-028, X-034, and X-037. The positive skin factor may be caused by liquid condensation in the vicinity of these wells.

The results of our analysis for the 11 wells selected from X field are summarized in Table 1. The OGIP computed using our approach is consistent – that is, each of the well analyses yields the same estimate of OGIP for the entire X field. The methodology assumes that the OGIP is constant; therefore, we should be able to force all analyses to a single value of gas-in-place, which is obtained in this analysis.

<table>
<thead>
<tr>
<th>Well Name of X Field (Tcf)</th>
<th>OGIP (md-ft)</th>
<th>kh (Asymptotic)</th>
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</thead>
<tbody>
<tr>
<td>X-II-01</td>
<td>19.8</td>
<td>2,946</td>
</tr>
<tr>
<td>X-II-03</td>
<td>19.8</td>
<td>1,313</td>
</tr>
<tr>
<td>X-II-04</td>
<td>19.8</td>
<td>1,762</td>
</tr>
<tr>
<td>X-II-16</td>
<td>19.8</td>
<td>857</td>
</tr>
<tr>
<td>X-III-02</td>
<td>19.8</td>
<td>2,791</td>
</tr>
<tr>
<td>X-III-03</td>
<td>19.8</td>
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<td>19.8</td>
<td>2,422</td>
</tr>
<tr>
<td>X-III-05</td>
<td>19.8</td>
<td>908</td>
</tr>
<tr>
<td>X-III-06</td>
<td>19.8</td>
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</tr>
<tr>
<td>X-III-09</td>
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<tr>
<td>X-III-15</td>
<td>19.8</td>
<td>1,106</td>
</tr>
</tbody>
</table>
Conclusions
This work provides the following conclusions:
1. The multiwell provides a more accurate analysis compared to the single well approach. This is indicated by a much better match on type curve model using the multiwell approach instead of using the single well approach.
2. The multiwell approach yields consistent value of field OGIP obtained from analysis of every well. The local flow capacity in the vicinity of the well can also be estimated.
3. This work proposes the computation of skin factor using the multiwell approach, which was not resolved in the previous work.

Nomenclature

\begin{align*}
A &= \text{area, } ft^2 \\
B &= \text{formation volume factor, } RB/STB \\
c_t &= \text{total compressibility, } psi^{-1} \\
G_p &= \text{cumulative gas production, MMscf} \\
h &= \text{net pay thickness, } ft \\
k &= \text{permeability, } md \\
N &= \text{original oil-in-place, } STB \\
N_p &= \text{cumulative oil production, } STB \\
n_{\text{well}} &= \text{number of wells} \\
p &= \text{pressure, psia} \\
p_i &= \text{initial pressure, psia} \\
p_p &= \text{pseudopressure function, psia} \\
p_{wf} &= \text{well flowing pressure, } psi \\
q &= \text{flow rate, } STB/D \\
q_g &= \text{gas flow rate, MSCF/D} \\
q_{\text{field}} &= \text{total field gas flow rate (all wells), MSCF/D} \\
q^\text{field} &= \text{total field flow rate (all wells), } STB/D \\
r_e &= \text{reservoir radius, } ft \\
r_w &= \text{wellbore radius, } ft \\
s &= \text{near-well skin factor, dimensionless} \\
t &= \text{time, day} \\
t_a &= \text{pseudotime, day} \\
t_{\text{tot}} &= \text{total material balance pseudotime, day} \\
t_{\text{mat}} &= \text{total material balance time, day} \\
x &= \text{x coordinate from origin, } ft \\
y &= \text{y coordinate from origin, } ft \\
x_e &= \text{reservoir size in the x direction, } ft \\
y_e &= \text{reservoir size in the y direction, } ft \\
x_o &= \text{x coordinate of well from origin, } ft \\
y_o &= \text{y coordinate of well from origin, } ft \\
z &= \text{gas z-factor} \\
\beta &= \text{multiwell interaction coefficient, dimensionless} \\
\mu &= \text{fluid viscosity, cp} \\
\tau &= \text{dummy variable} \\
\phi &= \text{porosity, fraction} 
\end{align*}

Subscripts

\begin{align*}
A &= \text{area is used as the reference} \\
\text{avg} &= \text{average} \\
\text{bar} &= \text{evaluation is performed at average pressure} \\
\text{base} &= \text{arbitrary reference} \\
\text{cr} &= \text{constant rate} \\
D &= \text{dimensionless} \\
k,i &= \text{well index} \\
MP &= \text{match point} \\
mw &= \text{multiwell} \\
ref &= \text{reference} 
\end{align*}

References

1. Fetkovich, M.J.:"Decline Curve Analysis Using Type Curves," 
   \textit{JPT} (June 1980) 1065-1077.
Figure 1 – Effect of adding new well on well drainage area: (a) before; (b) after.

Figure 2 – Effect of changing production on well drainage area: (a) before; (b) after.

Figure 3 – Bounded rectangular reservoir with multiple wells located at arbitrary positions within the reservoir.

Figure 4 – Decline type curve for unfractured vertical well in a multiwell reservoir system.
Figure 5 – Layout of X field and well location.

Figure 6 – Production history of Well X-III-02 (X-015).

Figure 7 – Decline type curve match of Well X-III-02 (X-015) – single well and multiwell approaches.

Figure 8 – Log-log plot of rate/pressure drop functions versus total material balance pseudotime for 11 wells of X Field – note that all curves converge to a unique material balance trend.

Figure 9 – Decline type curve match for 11 wells of X field.

Figure 10 – Skin factor for 11 wells of X field.