Decline Curve Analysis Using Type Curves — Evaluation of Well Performance Behavior in a Multiwell Reservoir System
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Abstract
In this paper we present a new multiwell reservoir solution and an associated analysis methodology to analyze single well performance data in a multiwell reservoir system. The key to this approach is the use of FIELD cumulative production data and individual well flowrate and pressure data. Our new solution and analysis methodology "couples" the single well and multiwell reservoir models — and permits the estimation of total reservoir volume and flow properties within the drainage area of an individual well — where the analysis is performed using a SINGLE WELL reservoir model (type curve). This "multiwell analysis" using a "single well model" is made possible by a "coupling" of the single well and multiwell solutions based on a total material balance of the system. The data required for this approach are readily available in practice: basic reservoir properties, fluid properties, well completion data, and well rate (and pressure) data and cumulative production data for the entire field.

Currently, ALL existing decline type curve analyses assume a single well in closed system (or single well with constant pressure or prescribed influx at 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.

Further, it is well established that new wells "steal" reserves from older wells, and this behavior is commonly observed in the production behavior. Our new approach 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 work provides the following deliverables:

1. A new solution for a multiwell reservoir where the formulation of this solution yields a simplified form for an arbitrary (individual) well during boundary-dominated flow conditions.
2. A complete analysis methodology for oil and gas reservoir systems based on conventional production data (on a per well basis) as well as the cumulative production of the entire field.
3. A systematic validation of this approach using a numerical reservoir simulator for cases of homogeneous, regionally heterogeneous, and randomly heterogeneous reservoirs.
4. An application to a large gas field (Arun Field, Indonesia). This analysis provides very consistent estimates of in-place fluids and reservoir properties. All of these analyses (simulated and field data) clearly demonstrate that the effects of "well interference" on individual wells have been eliminated as a result of this analysis methodology.

Introduction
The single well model has been widely used to forecast the production decline of wells-reservoir systems. Although the analytical solutions for single well in circular reservoir came as early as in 1934, this effort was pioneered by Arps’ who presented a suite of (empirical) exponential and hyperbolic models for this purpose.

Fetkovich (1973) presented theoretical basis for Arps's production decline models using the pseudosteady-state flow equation. He also developed decline type curves that not only permit us to forecast well performance, but also allow us to estimate reservoir properties (i.e., flow capacity — $k h$) as well as oil-in-place. This classic work by Fetkovich laid the foundation for all of the work that followed regarding decline type curves.

McCray (1990) developed a time function that would transform production data for systems exhibiting variable rate or pressure drop performance into an equivalent system
produced at a constant bottomhole pressure (this work was later extended by Blasingame, et al.\textsuperscript{5} (1991) to an equivalent "constant rate" analysis approach). In 1993, Palacio and Blasingame\textsuperscript{6} developed a solution for the general case of variable rate/variable pressure drop for the flow of either single-phase liquid or gas.

Rodriguez and Cinco-Ley\textsuperscript{7} (1993) developed a model for production decline in a bounded multiwell system. The primary assumptions in their model are that the pseudosteady-state flow condition exists at all points in the reservoir, and that all wells produce at a constant bottomhole pressure. They concluded that the production performance of the reservoir was shown to be exponential in all cases, as long as the bottomhole pressures in individual wells are maintained constant. Later in 1996, Camacho, et al.\textsuperscript{8} improved the Rodriguez-Cinco-Ley model by allowing individual wells to produce at different times. However, Camacho et al. also assumed the existence of the pseudosteady-state condition and that all wells produce at constant bottomhole pressures.

Valko, et al.\textsuperscript{9} (2000) presented a "multiwell productivity index" concept for an arbitrary number of wells in a bounded reservoir system. These authors also assume the existence of pseudosteady-state flow, but proved that the concept was valid for constant rate, constant pressure, or variable-rate/variable pressure production.

The limitations of the available multiwell models are summarized as follows:

- Constant bottomhole pressure production (except for Valko, et al. — ref. 9). This is rarely the case in practice.
- The assumption of pseudosteady-state may be violated, especially for conditions where the production schedule (rate/pressure) changes dramatically, or where the reservoir permeability is very low, and/or if the well spacing changes (due to infill wells).
- None of the available multiwell methods provide mechanisms for rigorous production data analysis.

In this work, we have developed a general multiwell solution that is valid for all flow regimes (transient, transition, and boundary-dominated flow). This solution is also rigorous for any rate/pressure profile (constant rate, constant pressure, or variable rate/pressure). Finally, this new solution provides a mechanism for the analysis of production data based on a material balance for the entire reservoir system.

Decline Curve Analysis in a Multiwell Reservoir System.

Motivation. Fig. 1 is a typical p/z plot of a gas well producing from Arun field (Indonesia). The data plotted in this figure is taken from Syah.\textsuperscript{10} This plot is characterized by "convex downward" behavior that could easily be interpreted as an "abnormal pressure" system. However, application of the material balance that accounts for abnormal pressure mechanisms does not validate that assumption.

Fig. 2 illustrates an attempt to match the well performance data functions with the single well decline type curve as proposed by Palacio and Blasingame.\textsuperscript{5} We observe that the well performance data functions deviate from the b=1 stem during boundary dominated flow condition (the b=1 stem represents the material balance model for the reservoir system). This behavior (i.e., data functions deviating from the material balance trend) has been consistently observed for the analysis of well performance data from Arun field.\textsuperscript{10}

It is interesting that the p/z versus Gp plot for the total field performance at Arun Field shows a straight-line trend — as would be expected for a volumetric gas reservoir (Fig. 3). This observation suggests that the behavior observed in Figs. 1 and 2 is perfectly correct — individual wells compete for reserves, while the cumulative (or aggregate) performance of the system is represented by a total balance of pressure and production.

In other words, if we intend to consider the local performance of an individual well, then the effects of other nearby wells must also be considered. To prove this point — we cannot rely solely on total field analyses (such as shown in Fig. 3) because the computation of the average pressure from the total field is based on an averaging of the available "local" pressure measurements.

This averaging technique itself may yield numerical artifacts — and the issue of accuracy/relevance of the local pressures becomes quite important. How accurate/representative are these locally averaged pressures? We should be able to develop an analysis/interpretation approach that is rigorous, yet does not rely on an average reservoir pressure scheme. This issue has been our motivation for the proposed work.

Our strategy is to develop a "multiwell" data analysis method using a general multiwell model — but to develop this model in such a form that it utilizes individual well performance data in the estimation of total reserves and the permeability in the drainage region for a particular well.

Multiwell Solution. The general solution for the well performance in a bounded multiwell reservoir system is given by: (see Appendix A for details)\textsuperscript{11}

\[
p_D(t_{DA}) = \sum_{j=1}^{n} \int_{0}^{t_{i}} q_{DA}(\tau) \left( \frac{d P_{DA}(t_{DA} - \tau)}{d \tau} \right) \, d\tau \\
+ q_{DK}(t_{DA}) x_{ki} \]

The physical model used to develop Eq. 1 is shown in Fig. 4. 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 solution for a single well produced at a constant rate in a bounded rect-
angular reservoir is given by Eq. A-11 (or Eq. A-12). 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.

The accuracy of Eq. 1 is validated using numerical reservoir simulation. We utilize a homogeneous square reservoir of constant thickness and include nine wells in the system and use a regular well pattern. Each well is permitted an arbitrary bottomhole flowing pressure that can vary with time (Fig. 5). This solution can also include an arbitrary flowrate scheme.

The reservoir and well configuration are shown in Fig. 6, and the reservoir and fluid property data for this case are given in Table 1. The computation of the oil flowrate from both the analytical solution and numerical reservoir simulation are plotted in Fig. 7. We note that the analytical solution is in very close agreement with numerical solution.

Decline Type Curve Analysis for a Multiwell Reservoir System. Having developed and validated our multiwell solution, we proceeded with the development of a data analysis methodology that could be derived from the multiwell solution. In Appendix B we show that Eq. 1 can be written as:

$$q_i(t) = \frac{1}{\tau_{tot,K}} \tau_{tot} + f(t)$$

where:

$$\tau_{tot,K} = \frac{1}{q_i(t)} \int_0^t q_i(\tau)d\tau = \frac{N_{p,dt}}{q_i(t)}$$

The variable $f(t)$ is obviously time-dependent (see Appendix B) — however, this variable becomes constant during boundary-dominated flow conditions. Eq. 2. represents a general formulation of the Arp’s harmonic decline equation and should be recognized as a material balance relation. We should note that this formulation accounts for the variations in production schedules that occur in practice — in particular, the approach is valid for constant rate, constant pressure, or variable rate/pressure behavior during boundary-dominated flow conditions. This equation suggests that if we plot $q_i(t)/(p_t - p_{w,t}(t))$ versus the “total material balance time” function then we can estimate the original-oil-in-place for the en-tire reservoir using decline type curves.

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

$$q_{D,de} = \frac{1}{t_{D,de}} + 1$$

where:

$$q_{D,de} = \frac{1412.2\mu}{kh} \left[ \frac{q_i(t)}{(p_t - p_{w,t}(t))} \right] \ln \left[ r_{t,de} \sqrt{p_t} \right] - \frac{1}{2}$$

$$t_{D,de} = \frac{0.00633 k^2}{\phi \mu c, A} \ln \left[ r_{t,de} \sqrt{p_t} \right] - \frac{1}{2}$$

This result states that the performance of an individual well in a multiwell system will behave as a single well in a closed system — provided we use the “total material balance time” function. 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 proper the definition of dimensionless variables are used (Eqs. 5 and 6).

To validate our concept we use Eq. 1 as a mechanism to generate the behavior of a multiwell reservoir system. This is a substantial departure from the work of Fetkovich (and others) where a well centered in a closed circular reservoir is used as the reservoir model. In particular, we use square reservoir with 9 wells on a regular well spacing producing at the same constant rate.

Using the case described above we found that we can produce results that are essentially identical to the Fetkovich/McCray type curve developed for a single well. For the multiwell reservoir case we plot $q_{D,de}$ versus $t_{D,de}$ on log-log scale and use $r_{t,de}/\sqrt{p_t}$ as the “family” parameter (as shown in Fig. 8). We have defined an “interaction coefficient,” $\beta_{D}$, which is used to represent the other wells in the multiwell system. An interaction coefficient of 1 is the single well case, and, consequently, is a special case of multiwell model.

For gas reservoirs, Eqs. 1 to 6 are valid — provided that we use the appropriate pseudopressure, pseudotime and total material balance pseudotime functions, these functions are used to replace pressure, time, and the total material balance time, respectively. The pseudopressure and pseudotime functions are defined by:

$$p_p = \left[ \frac{1}{\mu} \right] \int_{P_{phase}}^P p' dp'$$

$$t_u = \left[ \frac{1}{\mu c, \nu} \right] \int_0^z \frac{1}{\nu c, \nu} dz$$

And the total material balance pseudotime is expressed as:

$$\tau_{u,dt} = \left[ \frac{1}{\mu c, \nu} \right] \int_0^z \frac{d\tau}{\nu c, \nu}$$

Application of Multiwell Model to Simulated Cases

Homogeneous Reservoir Example. In this particular case we can directly validate the multiwell solution proposed in the previous section. The reservoir/well configuration is shown in Fig. 5 and the well performance behavior is shown in Figs. 5 and 7. The important issue to be considered for this case is that the analytical solution (Eq. 1) and the numerical simulation model represent exactly the same case — a homogeneous, bounded rectangular reservoir. Validation of the analytical solution for this case will imply (as would any reservoir engi-
neering solution) that this result can be used for the analysis and interpretation of performance data.

The well performance data for all wells is plotted on a log-log scale in Fig. 9. We note that all of the data trends taken from all nine wells (each with a different production schedule) overlay one another. The behavior at early times (all trends overlay) confirms the homogeneous nature of the reservoir, while the alignment of all of the data at late times confirms our total material balance on the entire reservoir system. An important note is that we have not modified any data or data trend shown in Fig. 9 — the excellent agreement of these data is solely due to the accuracy of the new solution.

The true value of this example is the confirmation that the performance of a single well can be used to establish the reservoir volume. We also note that it appears that the early time (transient flow) data can be used to estimate the permeability in the "local" drainage area for each well. We will attempt to confirm this hypothesis via the "locally homogeneous" and "heterogeneous" reservoir cases to be considered in the following sections.

Another advantage of using our multiwell approach (using the "total material balance time" function) over the single well approach (the "material balance time" function for a single well) can be observed in Fig. 10. This figure shows the performance of well [3,2] — the data are plotted on a log-log scale using both the single and multiwell approaches. The data for the multiwell approach are denoted by the open-symbols and these data clearly match the type curve model best for all flow regimes (transient, transition, and boundary-dominated flow regimes).

The data for the single well approach (solid-symbols) deviate systematically from the decline type curve model — quite significantly during boundary-dominated flow. Any analyses based on this match of the data could easily yield erroneous results.

In order to extend this approach for the analysis of gas well performance, we must extend the concept of our material balance time function to include the total gas production. This requires modification of the pseudotime formulation for the gas reservoir case and combination with the "material balance time" concept. This is relatively straightforward (see Eq. 9). The remainder of this section is devoted to the validation of the gas well performance case.

Figs. 11 to 13 show the application of our multiwell decline type curve method to simulated performance data from a homogeneous, dry gas reservoir. The well/reservoir configuration is the same as for oil case (Fig. 6). The fluid and reservoir properties are given in Table 2. Fig. 13 indicates that all of the well performance data imply a particular reservoir volume (i.e., a unique original gas-in-place) as predicted by our multiwell analysis technique. This behavior is denoted by the convergence for all of the boundary-dominated data (i.e., the late time data) for all wells into a single material balance trend.

Locally Homogeneous Reservoir Example. In this example, the reservoir and fluid properties are the same as those given in Table 1. The primary difference in this case is that the reservoir permeability distribution is not homogeneous, but is considered "locally" homogeneous (Fig. 14).

Similar to the previous case, a numerical simulation is performed where each well is produced under variable bottomhole flowing pressure conditions. The bottomhole pressure profile for each well is shown in Fig. 15, and the oil flowrate response for each well is shown in Fig. 16.

The well performance data for all wells are plotted on a log-log scale as shown in Fig. 17. We note that all of the data trends converge to a single material balance trend at late times, which corresponds to a unique reservoir volume. We also note that the different responses at early times correspond to the different average permeabilities for the drainage areas defined by individual wells. The data in Figs. 17 and 18 clearly show the ability of our multiwell approach to model the entire system based on the well performance data for individual wells.

Simultaneous matching of the data for all wells using the Fetkovich/McCray decline type curve is shown on Fig. 18. We see that the data for all wells match the type curve very well for all flow regimes (transient, transition, and boundary-dominated flow). The data are a bit scattered in the transition flow regime, where this behavior is due to a sudden change of the well flowing condition — gradual, rather than sudden, changes in rates and pressures are more likely practice. The results for this example are given in Table 3.

We note an excellent agreement between input and calculated values of original oil-in-place — but this is somewhat expected as the "total material balance time" correlates with total (in-place) volume. The differences in estimated permeability values occur because of the frame of reference. The "input" permeability is the value assigned to the well spacing for a particular well—the "calculated" permeability is the harmonic average of the permeabilities encountered in the "drainage area" of a particular well. The issue of a "drainage area" for an individual well in a multiwell reservoir system is somewhat problematic as these "drainage area" change with time — corresponding to changes in the production schedule for all of the wells in the entire reservoir.

Heterogeneous Reservoir Example. This case differs from substantially from the two previous cases in that the reservoir permeability distribution is random (see Fig. 19) — the permeability values are assigned to grid blocks arbitrarily from 0.1 md to 10 md and vary throughout the well spacing and the entire reservoir. This case is intended to demonstrate how well our multiwell analysis/interpretation approach works for a randomly heterogeneous reservoir. The reservoir and fluid properties are given in Table 1. The specified bottomhole flowing pressure profiles for each well are also different from the two previous cases (Fig. 20), and the oil flowrate response for each well is shown in Fig. 21.
The well performance data for all wells are shown on log-log scale in Fig. 22. Again, we note that all well responses converge to a single material balance trend at late times, which (again) corresponds to a unique reservoir volume. As we noted for the "locally homogeneous" reservoir, the different trends at early times are due to the different average permeabilities taken within an individual well's drainage area.

In Fig. 23 we note that all of the data trends match the correct (material balance) solution at late times (i.e., boundary dominated flow). The variations in the early time (transient flow) behavior corresponds to different permeabilities. The scattered data during the transition region is due to severe rate changes that affect the derivative computation. In practice, such severe rate changes are unlikely to occur. If such rate changes do occur, we could always "screen" the "bad data" to provide a smoother derivative function. The results of our analysis are provided in Table 4.

Again, we have an excellent agreement between the input and calculated values of original oil-in-place. The original oil-in-place (OOIP) is a unique property of the reservoir, and using our multiwell approach preserves this uniqueness (based on the "total material balance time").

Although it is somewhat unclear as to how to compare "input" and "calculated" permeability values for each well, we have chosen to compare the harmonic average permeability within a particular well spacing to the calculated permeability from the decline type curve match. The results in Table 4 confirm our proposition that this approach can be used to estimate permeabilities in a heterogeneous multiwell reservoir system.

Field Application

To demonstrate the application of our method to field data, we analyze several well performance data cases taken from Arun Field (Indonesia). Arun Field has approximately 111 wells (79 producers, 11 injectors, 4 observation wells, and 17 wells have been abandoned). The layout of Arun Field is shown in Fig. 24. This case would certainly be considered a multiwell reservoir system.

Arun Field is a supergiant gas condensate reservoir with a maximum liquid dropout of approximately 1.5% at the dew point (though most data suggest that maximum liquid production will be less than 1 percent). 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 expect 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 have analyzed selected cases of well performance data taken from Arun Field — in particular, the selected wells are:

- Well C-II-01 (A-037)
- Well C-II-03 (A-032)
- Well C-II-04 (A-024)
- Well C-II-16 (A-029)
- Well C-III-02 (A-015)
- Well C-III-15 (A-041)
- Well C-III-03 (A-034)

We will discuss in detail the analysis results obtained using the production data from Well C-III-02 (A-015). The production history of Well C-III-02 (A-015) (wellhead pressure and gas rate versus time) is plotted in Fig. 25. We note that this production history includes both wellhead flowrates and flowing wellhead pressure data.

In this example, we use both single-well (i.e., the single well material balance pseudotime) and our proposed multiwell decline type curve analysis techniques (i.e., the total material balance pseudotime). The decline type curve match for both the single and multiwell approaches are shown in Fig. 26. We note in Fig. 26 that our multiwell analysis approach matches the production data functions (solid symbols) to the type curve very well (we have 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 we note that the boundary-dominated flow data deviate systematically from the type curve (Fig. 26, open symbols). We recognize that this behavior is due to "well interference" effects caused by competing producing wells, but, using the "single well" approach we have no mechanism to correct or account for this "well interference" behavior.

Our analysis using the multiwell approach yields an estimate of the original gas-in-place for Arun Field of approximately 19.8 TCF. The estimate of effective flow capacity (to gas) for this well is 2,791 md-ft, where this is based on the match of the early-time (transient flow data).

Fig. 27 and 28 show the log-log plot of rate/pressure drop and the decline type curve match for all 11 wells that we have considered for our combined analysis. We note that all curves converge to the unique material balance trend at late times. This region (the boundary-dominated flow data) will be used to establish an estimate of total (in-place) gas reservoirs for Arun Field.

The results of our analysis for the 11 wells selected from Arun Field are summarized in Table 5. The original-gas-in-place computed using our approach is consistent — that is, each of the well analyses yields the same estimates of original-gas-in-place for the entire Arun Field. Our methodology assumes that the original gas-in-place is constant, therefore we should be able to force all analyses to a single value of gas-in-place, which is what we have done).

Conclusions

The following conclusions are derived from this work:

- We have developed a general multiwell solution that is accurate and provides a mechanism for the analysis of production data from a single well in a multiwell reservoir system.
We have developed a methodology for the analysis of production data taken from an individual well in a multiwell system. Using this method we can estimate the original fluid-in-place for the entire reservoir, as well as the local permeability. Our methodology can be applied for both oil and gas reservoirs.

Our approach uses the single-well decline type curve \( (i.e., \text{the Fekovich/McCray type curve}) \) coupled with the appropriate data transforms for the multiwell reservoir system. We developed a "total material balance time" plotting function, which includes the performance from all of the producing wells in the multiwell reservoir system.

Our method honors the volumetric balance of the entire reservoir and preserves the uniqueness of the reservoir volume. Further, the estimates of flow capacity (or permeability) obtained from our numerical simulation studies indicate that our approach provides estimates that are both accurate and representative — for homogeneous and heterogeneous reservoir systems.

### Nomenclature

- \( A \) = area, \( ft^2 \)
- \( B \) = formation volume factor, \( RB/STB \)
- \( c_r \) = total compressibility, \( psi^{-1} \)
- \( h \) = net pay thickness, \( ft \)
- \( n \) = original oil-in-place, \( STB \)
- \( N_p \) = cumulative oil production, \( STB \)
- \( n_{well} \) = number of wells
- \( p \) = pressure, \( psia \)
- \( P_{ref} \) = well flowing pressure, \( psia \)
- \( p_i \) = initial pressure, \( psia \)
- \( q \) = flowrate, \( STB/D \)
- \( q_g \) = gas flowrate, \( MSCF/D \)
- \( q_{tot} \) = total flowrate (all wells), \( STB/D \)
- \( q_{g,tot} \) = total gas flowrate (all wells), \( MSCF/D \)
- \( r_w \) = wellbore radius, \( ft \)
- \( s \) = near well skin factor, dimensionless
- \( t \) = time, \( day \)
- \( t_s \) = pseudotime, \( day \)
- \( \tau_{tot} \) = total material balance time, \( day \)
- \( \tau_{ps} \) = total material balance pseudotime, \( day \)
- \( x = x \) coordinate from origin, \( ft \)
- \( y = y \) coordinate from origin, \( ft \)
- \( x_w = x \) coordinate of well from origin, \( ft \)
- \( y_w = y \) coordinate of well from origin, \( ft \)
- \( \mu \) = fluid viscosity, \( cp \)
- \( \phi \) = porosity, \( fraction \)

### Subscripts

- \( ref \) = reference
- \( D \) = dimensionless
- \( m_w \) = multiwell
- \( k,i \) = well index
- \( c_r \) = constant rate

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### References


### Appendix A—General Solution for Multiwell System

The mathematical model describing the pressure behavior in a bounded rectangular reservoir with multiple wells is given in ref. 11. In this model each well produces at an arbitrary
constant rate and any well can be located at an arbitrary position in the reservoir (as shown in Fig. 4). This solution is given as:

\[
\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2} - \sum_{n=1}^{\infty} q(t) B \frac{A h(k/\mu)}{k} \delta(x - x_n, y - y_n) = \frac{\phi \mu_c}{k} \frac{\partial p}{\partial t} \quad (A-1)
\]

Eq. A-1 can be written in terms of the traditional dimensionless variables as follows:

\[
\frac{\partial^2 p_D}{\partial x_D^2} + \frac{\partial^2 p_D}{\partial y_D^2} + 2 \sum_{n=1}^{\infty} q_D(t_D) \delta(x_D - x_n, y_D - y_n) = \frac{\partial p_D}{\partial t_D} \quad (A-2)
\]

where:

\[
p_D = \frac{2 \pi k h}{q_{ref} B h}, \quad t_D = \frac{k t}{\phi \mu_c r_D} \quad \text{(Darcy Units)}
\]

In Field units, the dimensionless variables are defined as:

\[
p_D = \frac{k h (p - p(x, y, t))}{141.2 q_{ref} B h}, \quad t_D = 0.00633 k t
\]

Taking advantage of Duhamel’s principle for variable-rate/variable pressure systems, we obtain the following solution of Eq. A-2 — subject to the presumed no-flow outer boundary condition:

\[
p_D(x_D, y_D, t_D) = 2 \pi \sum_{n=1}^{\infty} \int_0^{t_D} q_D(t) \psi(x_D, y_D, t_D, t_D - \tau, x_n, y_n) d\tau
\]

... (A-3)

where \(\psi(x_D, y_D, t_D, x_n, y_n)\) is an instantaneous line source solution with unit strength located at \((x_n, y_n)\). From Eq. A-3, we can write the constant rate solution for single well as:

\[
p_D(x_D, y_D, t_D) = 2 \pi \int_0^{t_D} \psi(x_D, y_D, t_D, t_D - \tau, x_n, y_n) d\tau \quad (A-4)
\]

Defining \(\xi = t_D - \tau\), we then use this definition in Eq. A-4 and we obtain:

\[
p_D(x_D, y_D, t_D) = 2 \pi \int_0^{t_D} \psi(x_D, y_D, t_D - \tau, x_n, y_n) d\tau \quad (A-5)
\]

Taking the derivative of Eq. A-5 with respect to \(t_D\), we obtain:

\[
\frac{\partial p_D(x_D, y_D, t_D)}{\partial t_D} = 2 \pi \psi(x_D, y_D, t_D - \tau, x_n, y_n) \quad (A-6)
\]

Substituting Eq. A-6 into Eq. A-3, we obtain the convolution integral formulation for the pressure response at any location in an arbitrary multiwell reservoir system.

\[
p_D(x_D, y_D, t_D) = \frac{2 \pi}{\pi} \sum_{n=1}^{\infty} \int_0^{t_D} q_D(t) \frac{\partial p_D(x_D, y_D, t_D - \tau, x_n, y_n) d\tau}{d t_D}
\]

... (A-7)

If all wells are produced at individual (constant) flowrates, Eq. A-7 can be simplified to yield:

\[
p_D(x_D, y_D, t_D) = \sum_{n=1}^{\infty} q_D(x_D, y_D, t_D, x_n, y_n) \quad (A-8)
\]

Using Eq. A-7, the pressure solution for well "k" is given by:

\[
p_D(x_n, y_n, t_D) = \int_0^{t_D} \frac{\partial p_D(x_n, y_n, t_D - \tau, x_n, y_n) d\tau}{d t_D}
\]

... (A-9)

To account for the effect of the near-well skin factor, \(s\), at well "k", we use:

\[
p_D(x_n, y_n, t_D) + q_D(t_D) s_k \quad (A-10)
\]

The constant rate solution for an arbitrary location in a bounded rectangular reservoir is given by:

\[
p_D(x_D, y_D, t_D) = 2 \pi \sum_{n=1}^{\infty} \int_0^{t_D} \psi(x_D, y_D, t_D - \tau, x_n, y_n) d\tau
\]

... (A-11)
From ref. 10 we note that Eq. A-11 can also be written in the form of an exponential integral series:

\[ P_{D_{DA}}(x_{DA}, y_{DA}, t_{DA}) = \frac{1}{2} \sum_{n=0}^{\infty} \sum_{m=0}^{\infty} \left[ E_1 \left( \frac{(x_{DA} - x) + 2n(x_{DA}) + (y_{DA} + y + 2m(y_{DA}))}{4t_{DA}} \right) \right. \]

\[ + E_1 \left( \frac{(x_{DA} - x) + 2n(x_{DA}) + (y_{DA} - y + 2m(y_{DA}))}{4t_{DA}} \right) \]

\[ + E_1 \left( \frac{(x_{DA} + x) + 2n(x_{DA}) + (y_{DA} - y + 2m(y_{DA}))}{4t_{DA}} \right) \]

\[ + E_1 \left( \frac{(x_{DA} + x) + 2n(x_{DA}) + (y_{DA} + y + 2m(y_{DA}))}{4t_{DA}} \right) \] \hspace{1cm} (A-12)

The pressure response for an individual well produced at a constant rate is given by:

\[ P_{D_{DA}}(x_{DA}, y_{DA}, t_{DA}) = 2 \pi t_{DA} \]

\[ + 4 \pi \sum_{n=1}^{\infty} \sum_{m=1}^{\infty} \left[ 1 - \exp \left( \frac{n^2 \pi^2}{x_{DA}} \right) \right] \cos \left( \frac{n \pi x_{DA}}{x_{DA}} \right) \cos \left( \frac{m \pi y_{DA}}{y_{DA}} \right) \]

\[ + 8 \pi \sum_{n=1}^{\infty} \sum_{m=1}^{\infty} \left[ 1 - \exp \left( \frac{n^2 \pi^2}{x_{DA}} + \frac{m^2 \pi^2}{y_{DA}} \right) \right] \]

\[ \times \cos \left( \frac{n \pi x_{DA}}{x_{DA}} + \frac{m \pi y_{DA}}{y_{DA}} \right) \cos \left( \frac{n \pi x_{DA}}{x_{DA}} + \frac{m \pi y_{DA}}{y_{DA}} \right) \] \hspace{1cm} (A-13)

Substituting Eq. A-12 into Eq. A-13 we obtain:

\[ P_{D_{DA}}(x_{DA}, y_{DA}, t_{DA}) = \]

\[ \frac{1}{2} \sum_{n=0}^{\infty} \sum_{m=0}^{\infty} \left[ E_1 \left( \frac{(2x_{DA} + \epsilon + 2n(x_{DA}))^2 + (2y_{DA} + \epsilon + 2m(y_{DA}))^2}{4t_{DA}} \right) \right. \]

\[ + E_1 \left( \frac{(2x_{DA} + \epsilon + 2n(x_{DA}))^2 + (2y_{DA} - \epsilon + 2m(y_{DA}))^2}{4t_{DA}} \right) \]

\[ + E_1 \left( \frac{(2x_{DA} + \epsilon + 2n(x_{DA}))^2 + (2y_{DA} + \epsilon - 2m(y_{DA}))^2}{4t_{DA}} \right) \]

\[ + E_1 \left( \frac{(2x_{DA} + \epsilon + 2n(x_{DA}))^2 + (2y_{DA} - \epsilon - 2m(y_{DA}))^2}{4t_{DA}} \right) \] \hspace{1cm} (A-14)

**Appendix B—Development of Production Data Analysis Technique in Multiwell System**

In this Appendix we develop the plotting functions that will serve as the basis for our proposed decline type curve analysis of well and field production performance data from a bounded multiwell reservoir system.

We begin by substituting Eq. A-13 into Eq. A-10 — this gives:

\[ P_{D_{DA}}(x_{DA}, y_{DA}, t_{DA}) = \]

\[ 2 \pi \sum_{n=0}^{\infty} \int_0^{\infty} q_{DA}(t) \tau \] \hspace{1cm} (B-1)

where:

\[ F([x_{DA} + \epsilon], [y_{DA} + \epsilon], [t_{DA} - \tau], x_{DA} + y_{DA} + \tau) = \]

\[ 2 \sum_{n=0}^{\infty} \exp \left( \frac{n^2 \pi^2}{x_{DA}} (t_{DA} - \tau) \right) \cos \left( \frac{n \pi x_{DA}}{x_{DA}} \right) \cos \left( \frac{n \pi y_{DA}}{y_{DA}} \right) \]

\[ + 2 \sum_{n=0}^{\infty} \exp \left( \frac{n^2 \pi^2}{y_{DA}} (t_{DA} - \tau) \right) \cos \left( \frac{n \pi x_{DA}}{x_{DA}} \right) \cos \left( \frac{n \pi y_{DA}}{y_{DA}} \right) \]

\[ + 4 \sum_{n=0}^{\infty} \sum_{m=0}^{\infty} \exp \left( \frac{n^2 \pi^2}{x_{DA}} + \frac{m^2 \pi^2}{y_{DA}} (t_{DA} - \tau) \right) \]

\[ \times \cos \left( \frac{n \pi x_{DA}}{x_{DA}} \right) \cos \left( \frac{m \pi y_{DA}}{y_{DA}} \right) \]

\[ \times \cos \left( \frac{n \pi x_{DA}}{x_{DA}} \right) \cos \left( \frac{m \pi y_{DA}}{y_{DA}} \right) \] \hspace{1cm} (B-2)

Writing Eq. B-1 in Field units and multiplying both sides by \( q_{DA} \) we obtain:

\[ \frac{kk}{4\pi r_{DF}^2} \left( \frac{P_{DA} - P_{DA,k}}{Q_{DA}} \right) = 2 \pi \frac{0.00633 k}{\mu_{w} \phi} \left( \tau \right) \int_0^{\infty} q_{DA}(t) \tau \]

\[ + 2 \pi \frac{0.00633 k}{\mu_{w} \phi} \]

\[ \left( \frac{1}{Q_{DA}} \right) \int_0^{\infty} \left( \sum_{i=1}^{\infty} q_i(t) \tau \right) F([x_{wA} + \epsilon], [y_{wA} + \epsilon], [t - \tau], x_{wA}, y_{wA}) \] \hspace{1cm} (B-3)

We immediately recognize that:

\[ N_{p,DA} = \left( \sum_{i=1}^{\infty} q_i(t) \right) \tau \] \hspace{1cm} (B-4)
Where \( N_{p_{out}} \) is the cumulative oil production for the entire field. Further, we now define a "total material balance time" as:

\[
\tau_{tot} = \frac{1}{q_{d}} \int_{t=0}^{t_{max}} q(t) \, dt = \frac{N_{p_{out}}}{q_{d}} \] ............................. (B-5)

Substituting Eq. B-5 into Eq. B-3, and multiplying both sides by 141.2\( B_{d} \mu (kh) \), we obtain:

\[
\frac{(p - p_{well}(t))}{q_{d}(t)} = \frac{1}{Nc_{i}} \tau_{tot} + \frac{1}{N_{c_{i}}} \int_{t=0}^{t_{max}} q(t) \, dt \] ............................. (B-6)

For simplicity, we can write Eq. B-6 as:

\[
\frac{(p - p_{well}(t))}{q_{d}(t)} = \frac{1}{N_{c_{i}}} \tau_{tot} + f(t) \] ............................. (B-7)

Taking reciprocal of Eq. B-7, we obtain:

\[
\frac{q_{d}(t)}{(p - p_{well}(t))} = \frac{1}{N_{c_{i}}} \tau_{tot} + f(t) \] ............................. (B-8)

The variable \( f(t) \) is obviously time-dependent — however, this variable becomes constant during boundary dominated flow conditions. Eq. 8 is the general formulation of Arps' harmonic decline equation. This is an elegant relation considering that it is rigorous and yet simple. Specifically, this result takes into account the complexity of production schedule (constant rate, constant pressure, or variable rate/pressure).

The formulations given by Eqs. B-7 and B-8 are convenient for data analysis — except that \( f(t) \) is time-dependent. Nevertheless, during boundary-dominated-flow conditions this term becomes constant and we can treat the analysis of multiwell performance data in the same manner as the single well case. Our purpose is to use the traditional single well decline type curve analysis techniques to estimate (total) volume and (nearwell) flow properties simultaneously.

Recalling the boundary-dominated flow (or pseudosteady-state flow) solution for a single well, we have:

\[
\frac{q_{d}(t)}{(p - p_{well}(t))} = \frac{1}{N_{c_{i}}} \tau_{tot} + b_{ps} \] ............................. (B-9)

where:

\[
b_{ps} = 141.2 \frac{B_{d} \mu}{kh} \left[ \frac{4}{27} \frac{A}{\phi \mu c_{D} r_{D}^{4}} \right] \] ............................. (B-10)

For the multiwell case, the Dietz shape factor is determined not only by reservoir shape and well position but also by the state of the other wells (number, position and rate/pressure). The apparent drainage area of a well in multiwell system depends on the ratio of producing rate to total field producing rate. We call this ratio the "interaction coefficient", \( \beta_{D} \).

For boundary dominated flow, Eq. B-8 becomes:

\[
\frac{q_{d}(t)}{(p - p_{well}(t))} = \frac{1}{N_{c_{i}}} \tau_{tot} + b_{ps,mw} \] ............................. (B-11)

Where:

\[
b_{ps,mw} = 141.2 \frac{B_{d} \mu}{kh} \left[ \frac{4}{27} \frac{A}{\phi \mu c_{D} r_{D}^{4}} \right] \] ............................. (B-12)

Fetkovich\( ^{1} \) used a modified definition of the \( b_{ps} \) variable defined as:

\[
b_{ps} = 141.2 \frac{B_{d} \mu}{kh} \left[ \ln r_{D} \sqrt{B_{D}} - \frac{1}{2} \right] \] ............................. (B-13)

Eq. B-13 has been used as the defining "transform" variable for all of the decline type curves presented for the case of a single well centered in a bounded circular reservoir. Accordingly, we present an similar expression for the multiwell system. This result is given as:

\[
b_{ps,mw} = 141.2 \frac{B_{d} \mu}{kh} \left[ \ln r_{D} \sqrt{B_{D}} - \frac{1}{2} \right] \] ............................. (B-14)

Substituting Eq. B-14 into Eq. B-11 and multiplying both sides by 141.2\( B_{d} \mu (kh) \), we obtain:

\[
141.2 \frac{B_{d} \mu}{kh} \frac{q_{d}(t)}{(p - p_{well}(t))} = \frac{1}{2\pi} \left[ \frac{0.00633 k_{s} \tau_{tot}}{\phi \mu c_{D}} + \ln \left[ r_{D} \sqrt{B_{D}} - \frac{1}{2} \right] \right] \] ............................. (B-15)

Rearranging Eq. B-15 slightly, we finally arrive at the following formulation:

\[
141.2 \frac{B_{d} \mu}{kh} \frac{q_{d}(t)}{(p - p_{well}(t))} \left[ \ln \left[ r_{D} \sqrt{B_{D}} - \frac{1}{2} \right] \right] = \frac{1}{2\pi} \left[ \frac{0.00633 k_{s} \tau_{tot}}{\phi \mu c_{D}} + 1 \right] \] ............................. (B-16)

Defining the appropriate dimensionless "decline" variables:

\[
q_{De} = 141.2 \frac{B_{d} \mu}{kh} \frac{q_{d}(t)}{(p - p_{well}(t))} \] ............................. (B-17)

\[
t_{De} = \frac{0.00633 k_{s} \tau_{tot}}{\phi \mu c_{D} \ln \left[ r_{D} \sqrt{B_{D}} - \frac{1}{2} \right]} \] ............................. (B-18)

Hence we can write Eq. B-16 as:

\[
q_{De} = \frac{1}{t_{De} + 1} \] ............................. (B-19)

We immediately recognize that Eq. B-19 is the Arps "harmonic" decline relation. This result verifies that the production decline character of an individual well in a multiwell reservoir system gives the same behavior as a single well in a closed reservoir if we use the "total material balance
time." Furthermore, the Fetkovich/McCray type curves for a single well system can be used for the analysis/interpretation of performance from a multiwell reservoir system — provided that we use the appropriate definitions of the dimensionless variables (Eqs. B-18 and B-19).

Table 1 – Reservoir and Fluid Properties for Synthetic Example, Oil Reservoir.

<table>
<thead>
<tr>
<th>Reservoir Properties:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Pressure, (p_i)</td>
<td>5,000 psia</td>
</tr>
<tr>
<td>Reservoir Thickness, (h)</td>
<td>500 ft</td>
</tr>
<tr>
<td>Total Reservoir Area, (A)</td>
<td>6525.7 acres</td>
</tr>
<tr>
<td>Original-Oil-In-Place, OOIP = 4,278 MMSTB</td>
<td></td>
</tr>
<tr>
<td>Permeability, (k)</td>
<td>5 md</td>
</tr>
<tr>
<td>Well radius, (r_w)</td>
<td>0.5 ft</td>
</tr>
<tr>
<td>Porosity, (\phi)</td>
<td>0.2 (fraction)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid Properties:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Compressibility, (c_t)</td>
<td>3x10-6 psi-a-1</td>
</tr>
<tr>
<td>Oil Viscosity, (\mu)</td>
<td>0.8 cp</td>
</tr>
<tr>
<td>Oil Formation Volume Factor, (B)</td>
<td>1.184 RB/STB</td>
</tr>
</tbody>
</table>

Table 2 – Reservoir and Fluid Properties for Synthetic Example, Gas Reservoir.

<table>
<thead>
<tr>
<th>Reservoir Properties:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Pressure, (p_i)</td>
<td>5,000 psia</td>
</tr>
<tr>
<td>Reservoir Thickness, (h)</td>
<td>500 ft</td>
</tr>
<tr>
<td>Total Reservoir Area, (A)</td>
<td>6525.7 acres</td>
</tr>
<tr>
<td>Original-Gas-In-Place, OGIP = 6.34 TSCF</td>
<td></td>
</tr>
<tr>
<td>Permeability, (k)</td>
<td>5 md</td>
</tr>
<tr>
<td>Well radius, (r_w)</td>
<td>0.25 ft</td>
</tr>
<tr>
<td>Porosity, (\phi)</td>
<td>0.2 (fraction)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid Properties:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Formation Volume Factor, (B)</td>
<td>1.184 RB/STB</td>
</tr>
<tr>
<td>Gas Viscosity, (\mu_{gas})</td>
<td>0.001 cp</td>
</tr>
<tr>
<td>Gas Compressibility, (c_{gas})</td>
<td>0.0001 psi-a-1</td>
</tr>
</tbody>
</table>

Table 3 – Results of Multiwell Analysis (Locally Homogeneous Example).

<table>
<thead>
<tr>
<th>Well</th>
<th>Permeability, (k) (md)</th>
<th>Absolute Relative Error (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(calculated)</td>
<td>(input)</td>
<td></td>
</tr>
<tr>
<td>[1,1]</td>
<td>22.70</td>
<td>25</td>
</tr>
<tr>
<td>[1,2]</td>
<td>5.15</td>
<td>5</td>
</tr>
<tr>
<td>[1,3]</td>
<td>10.10</td>
<td>10</td>
</tr>
<tr>
<td>[2,1]</td>
<td>5.15</td>
<td>5</td>
</tr>
<tr>
<td>[2,2]</td>
<td>9.77</td>
<td>10</td>
</tr>
<tr>
<td>[2,3]</td>
<td>13.80</td>
<td>15</td>
</tr>
<tr>
<td>[3,1]</td>
<td>9.94</td>
<td>10</td>
</tr>
<tr>
<td>[3,2]</td>
<td>14.20</td>
<td>15</td>
</tr>
<tr>
<td>[3,3]</td>
<td>18.90</td>
<td>20</td>
</tr>
</tbody>
</table>

| Original Oil-In-Place (input) | 4,278 MMSTB |
| Original Oil-In-Place (calculated) | 4,278 MMSTB |

Table 4 – Results of Multiwell Analysis (Heterogeneous Example).

<table>
<thead>
<tr>
<th>Well</th>
<th>Permeability, (k) (md)</th>
<th>Absolute Relative Error (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>(calculated)</td>
<td>(input)</td>
<td></td>
</tr>
<tr>
<td>[1,1]</td>
<td>4.04</td>
<td>4.10</td>
</tr>
<tr>
<td>[1,2]</td>
<td>3.27</td>
<td>3.31</td>
</tr>
<tr>
<td>[1,3]</td>
<td>4.44</td>
<td>4.40</td>
</tr>
<tr>
<td>[2,1]</td>
<td>4.30</td>
<td>4.36</td>
</tr>
<tr>
<td>[2,2]</td>
<td>2.52</td>
<td>2.48</td>
</tr>
<tr>
<td>[2,3]</td>
<td>3.38</td>
<td>3.42</td>
</tr>
<tr>
<td>[3,1]</td>
<td>3.93</td>
<td>3.90</td>
</tr>
<tr>
<td>[3,2]</td>
<td>3.99</td>
<td>4.05</td>
</tr>
<tr>
<td>[3,3]</td>
<td>3.64</td>
<td>3.73</td>
</tr>
</tbody>
</table>

| Original Oil-In-Place (input) | 4,278 MMSTB |
| Original Oil-In-Place (calculated) | 4,278 MMSTB |

Table 5 – Summary of the Decline Type Curve Analysis Results for Arun Field, Indonesia (Multiwell Approach).

<table>
<thead>
<tr>
<th>Well Name</th>
<th>(\Delta t_{\text{PM}})</th>
<th>(\frac{q}{A_{PM}})</th>
<th>(\frac{r_{CD}}{\sqrt{P_D}})</th>
<th>OGIP (Tcf)</th>
<th>(kh) (md-ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>C-II-01</td>
<td>18,404</td>
<td>95</td>
<td>10,000</td>
<td>19.8</td>
<td>2,946</td>
</tr>
<tr>
<td>C-II-03</td>
<td>18,404</td>
<td>95</td>
<td>80</td>
<td>19.8</td>
<td>1,313</td>
</tr>
<tr>
<td>C-II-04</td>
<td>21,855</td>
<td>80</td>
<td>800</td>
<td>19.8</td>
<td>1,762</td>
</tr>
<tr>
<td>C-II-16</td>
<td>20,569</td>
<td>85</td>
<td>28</td>
<td>19.8</td>
<td>857</td>
</tr>
<tr>
<td>C-III-02</td>
<td>19,433</td>
<td>90</td>
<td>10,000</td>
<td>19.8</td>
<td>2,791</td>
</tr>
<tr>
<td>C-III-03</td>
<td>15,979</td>
<td>105</td>
<td>10,000</td>
<td>19.8</td>
<td>3,256</td>
</tr>
<tr>
<td>C-III-04</td>
<td>15,894</td>
<td>110</td>
<td>800</td>
<td>19.8</td>
<td>2,422</td>
</tr>
<tr>
<td>C-III-05</td>
<td>19,427</td>
<td>90</td>
<td>28</td>
<td>19.8</td>
<td>908</td>
</tr>
<tr>
<td>C-III-06</td>
<td>9,202</td>
<td>190</td>
<td>10,000</td>
<td>19.8</td>
<td>5,893</td>
</tr>
<tr>
<td>C-III-09</td>
<td>15,204</td>
<td>115</td>
<td>10,000</td>
<td>19.8</td>
<td>3,567</td>
</tr>
<tr>
<td>C-III-15</td>
<td>13,449</td>
<td>130</td>
<td>18</td>
<td>19.8</td>
<td>1,106</td>
</tr>
</tbody>
</table>
Figure 1 – Typical $p/z$ plot for a well in Arun Field (Well A-015).

Figure 2 – Decline type curve match using single well approach (Well A-015).

Figure 3 – $p/z$ plot for Arun Field (total field performance).

Figure 4 – Bounded rectangular reservoir with multiple wells located at arbitrary positions within the reservoir.

Figure 5 – Bottomhole flowing pressure profiles (homogeneous reservoir example).

Figure 6 – Homogeneous bounded square reservoir with nine producing wells (homogeneous reservoir example).
Figure 7 – Oil rate versus time profiles (homogeneous reservoir example). (O Numerical Simulation, — Analytical Solution)

Figure 8 – Dimensionless “decline variables” plot for the single well and multowell performance cases — simulated performance used to validate the multiwell concept.

Figure 9 – Log-log plot of rate/pressure drop functions as a function of total material balance time (homogeneous reservoir example).

Figure 10—Log-log plot of rate/pressure drop functions as a function of total material balance time (homogeneous reservoir example — all cases).

Figure 11—Bottomhole flowing pressure profiles for individual wells (gas, homogeneous reservoir example).

Figure 12—Gas flowrate profiles for individual wells (gas, homogeneous reservoir example).
Figure 13—Log-log plot of rate/pseudopressure drop functions versus total material balance pseudotime (gas, homogeneous reservoir example).

Figure 14—Locally homogeneous bounded square reservoir with nine producing wells (locally homogeneous reservoir example).

Figure 15—Bottomhole flowing pressure profiles for individual wells (locally homogeneous reservoir example).

Figure 16—Oil rate versus time profiles for individual wells (locally homogeneous reservoir example).

Figure 17—Log-log plot of the rate/pressure drop versus total material balance time (locally homogeneous example).

Figure 18—Decline type curve match using the multiwell approach (total material balance time) — locally homogeneous example.
Figure 19— Random permeability case, bounded square reservoir with nine producing wells (heterogeneous reservoir example).

Figure 20— Bottomhole flowing pressure profiles for individual wells (heterogeneous reservoir example).

Figure 21— Oil rate versus time profiles for individual wells (heterogeneous reservoir example).

Figure 22— Log-log plot of the rate/pressure drop versus total material balance time (heterogeneous reservoir example).

Figure 23— Decline type curve match using the multiwell approach (total material balance time)—heterogeneous reservoir example.

Figure 24— Layout of the Arun Field, Indonesia.

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**Arun Field**

- Located in Northern part of Sumatra, Indonesia
- Retrograde gas reservoir
- One of the largest gas fields in the world
- Arun Field has 111 wells:
  - 79 producers
  - 11 injectors
  - 4 observation wells
  - 17 wells have been abandoned
**Figure 25**—Production history of Well C-III-02 (A-015)—Arun Gas Field, Indonesia.

**Figure 26**—Decline type curve match of Well C-III-02 (A-015)—single-well and multiwell approaches.

**Figure 27**—Decline type curve match for 11 wells of Arun Field, Indonesia.

**Figure 28**—Decline type curve for 11 wells of Arun Field, Indonesia.