From Straight Lines to Deconvolution: The Evolution of the State of the Art in Well Test Analysis

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Summary

Well test analysis has been used for many years to assess well condition and obtain reservoir parameters. Early interpretation methods (by use of straight lines or log-log pressure plots) were limited to the estimation of well performance. With the introduction of pressure-derivative analysis in 1983 and the development of complex interpretation models that are able to account for detailed geological features, well test analysis has become a very powerful tool for reservoir characterization. A new milestone has been reached recently with the introduction of deconvolution. Deconvolution is a process that converts pressure data at variable rate into a single drawdown at constant rate, thus making more data available for interpretation than in the original data set, in which only periods at constant rate can be analyzed. Consequently, it is possible to see boundaries in deconvolved data, a considerable advantage compared with conventional analysis, in which boundaries often are not seen and must be inferred. This has a significant impact on the ability to certify reserves.

This paper reviews the evolution of well test analysis techniques during the past half century and shows how improvements have come in a series of step changes 20 years apart. Each one has increased the ability to discriminate among potential interpretation models and to verify the consistency of the analysis. This has increased drastically the amount of information that one can extract from well test data and, more importantly, the confidence in that information.

Introduction

Results that can be obtained from well testing are a function of the range and the quality of the pressure and rate data available and of the approach used for their analysis. Consequently, at any given time, the extent and quality of an analysis (and therefore what can be expected from well test interpretation) are limited by the state-of-the-art techniques in both data acquisition and analysis. As data improve and better interpretation methods are developed, more and more useful information can be extracted from well test data.

Early well test analysis techniques were developed independently from one another and often gave widely different results for the same tests (Ramey 1992). This has had several consequences:

- An analysis was never complete because there always was an alternative analysis method that had not been tried.
- Interpreters had no basis on which to agree on analysis results.
- The general opinion was that well testing was useless given the wide range of possible results.

Significant progress was achieved in the late 1970s and early 1980s with the development of an integrated methodology on the basis of signal theory and the subsequent introduction of derivatives. It was found that, although reservoirs are all different in terms of depth, pressure, fluid composition, geology, etc., their behaviors in well tests were made of a few basic components that were always the same. Well test analysis was about finding these components, which could be achieved in a systematic way, following a well-defined process. The outcome was a well test interpretation model, which defined how much and what kind of knowledge could be extracted from the data. The interpretation model also determined which of the various published analysis methods were applicable and when they were applicable. Importantly, the integrated methodology made well test analysis repeatable and easy to learn. The evolution of the state-of-the-art techniques in well test analysis throughout these years can be followed from review papers that have appeared at regular intervals in the petroleum literature (Ramey 1980, 1982, 1992; Gringarten 1986; Ehlig-Economides et al. 1990).

No major breakthrough occurred during the next 20 years, which instead saw minor improvements in existing techniques and the development of new, more complex interpretation models. In that period, the word "conventional" shifted in meaning from straightline to derivative analysis. The word "modern," previously attached to pressure log-log analysis, disappeared, suggesting that well test analysis had become mature.

A new milestone has been reached recently with the addition of a working deconvolution algorithm to the well test analysis tool kit. The impact of such a development on well test interpretation and its place in the evolution of well test analysis methods are discussed in the present paper.

History of Well Test Analysis

Looking back at the history of well test analysis in the oil industry, it is possible to identify different periods during which particular analysis techniques dominated and specific types of information prevailed **(Fig. 1).**

At the beginning, most analysis techniques came from groundwater hydrology, in which they had been used for many years. Examples include "semilog" straightline analyses, suggested by Theis (1935) and applied by Cooper and Jacob (1946), and type-curve matching, also introduced by Theis (1935).

The well test analysis methods prevailing during the 1950s and 1960s are described in SPE Monograph 1 by Matthews and Russell (1967) and SPE Monograph 5 by Earlougher (1977). These techniques, developed in oil companies and illustrated in the work of Miller et al. (1950) and Horner (1951), are based on straight lines and apply to middle time semilog data (Miller et al. 1950; Horner 1951; Warren and Root 1963; Odeh and Jones 1965) or to simple boundary effects (Muskat 1937; Horner 1951; Matthews et al. 1954; Jones 1956) at late times. The main mathematical technique used in those days was the Laplace transform as published by Van Everdingen and Hurst (1949). Interpretation techniques were designed to be performed exclusively by hand with pencil and graph paper. The emphasis was on production operations, and well test analysis results were usually limited to the determination of reservoir permeability, well skin effect or productivity index, drainage area, and average reservoir pressure.

During the late 1960s and early 1970s, most major developments originated from universities, led by H.J. Ramey Jr. The emphasis shifted toward the understanding of early-time behavior because it became apparent that some of the results from straightline analyses could be ambiguous (Ramey 1970). It was realized, for instance, that the skin was a global value that did not inform fully of the causes of well damage or stimulation and therefore did not provide a sound basis for operational decisions. Specifically, the same negative skin could be obtained from acidizing or from fracturing (Ramey 1970), and the same positive skin could be

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Date	Interpretation Method	Tools	Emphasis
50s	Straight lines	Laplace transform	Homogeneous reservoir behavior
Late 60s Early 70s	Pressure type-curve analysis	Green's functions	Near-wellbore effects
Late 70s	Type curves with independent variables	Integrated methodology Stehfest algorithm	Dual-porosity behavior
Early 80s	Derivatives	Computerized analysis	Heterogeneous reservoir behavior and boundaries
90s		Computer-aided analysis downhole rate measurements integration with interpretation models from other data	Multilayered reservoir
Early 00s		Deconvolution	Enhanced radius of investigation boundaries

Fig. 1—Summary of the history of well test analysis.

produced by well damage or result from partial penetration (Brons and Marting 1961) or multiphase flow around the well (Kazemi 1975). Type-curve analysis (Ramey 1970; Agarwal et al. 1970; McKinley 1971; Gringarten and Ramey 1974; Gringarten et al. 1974, 1975; Cinco-Ley et al. 1978; Agarwal et al. 1979) was introduced by Ramey (1970) to get an insight into the meaning of the skin and therefore on the means to cure it. Particular emphasis was placed on wellbore storage (Agarwal et al. 1970), high-conductivity fractures (Gringarten et al. 1975) and low-conductivity fractures (Cinco-Ley et al. 1978). Type-curve matching also provided a way to select the applicable straight line for semilog straightline analysis (Ramey 1970), which had been a major shortcoming in the past. New mathematical tools, such as the ones based on Green's functions (Gringarten and Ramey 1973) were also developed, which enabled new interpretation models (Gringarten and Ramey 1974; Gringarten et al. 1975; Cinco-Ley et al. 1978; Agarwal et al. 1979) to be generated. These improved further the understanding of early-time data as described in SPE Monograph 5 (Earlougher 1977). Analysis, however, was still mostly manual.

Starting in the late 1970s, most new developments came from service companies. Type-curve analysis was significantly enhanced when the concept of independent variables was introduced by Gringarten et al. (1979) and Bourdet and Gringarten (1980). This and the integrated well test analysis methodology that was developed at the same time (Gringarten et al. 1979; Gringarten 1984) made the analysis process easier. It also provided more consistent and more reliable analysis results. This period marked the beginning of the end of manual analysis, because the full application of the new, integrated methodology required the use of computers. With these and new numerical techniques such as the Stehfest's algorithm for Laplace inversion (Stehfest 1970), new interpretation models were developed that made it possible to identify more complex well behaviors such as double porosity (Gringarten et al. 1979; Bourdet and Gringarten 1980; Gringarten et al. 1981; Gringarten 1984). As a result, well test analysis started becoming more useful as a reservoir description tool, both during exploration and for reservoir simulation. At the same time, the usefulness of well test analysis in production operations was re-emphasized with the practical development of NODAL™ (Schlumberger) analysis (Mach et al. 1979).

Well test analysis became a true reservoir characterization tool with the introduction of derivatives by Bourdet et al. (1983a, 1983b). Derivatives have revolutionized well test analysis by making it possible to:

- Understand and recognize heterogeneous reservoir behaviors, such as double permeability (Bourdet 1985; Joseph et al. 1986) and composite (Chu and Shank 1993).
- Identify partial penetration or limited entry (Kuchuk and Kirwan 1987) and other near-wellbore effects.
- Analyze horizontal wells (Daviau et al. 1988).
- Handle a wide range of boundary effects (Clark and Van Golf-Racht 1985).

The power of well test analysis has been further extended recently with the introduction of an effective algorithm for deconvolution by von Schroeter et al. (2001). Deconvolution converts variable-rate pressure data into a constant-rate single drawdown with a duration equal to the total duration of the test. This makes more data available for interpretation and helps greatly in the identification of the interpretation model. For instance, deconvolution enables boundary effects to be seen although they may not appear in individual flow periods at constant rate.

The improvements in analysis techniques listed above are closely tied with improvements in data. Until the early 1970s, pressure measurements were performed with Bourdon-type mechanical gauges and were limited in resolution and accuracy. The overall quality of pressure data improved dramatically in the late 1970s and early 1980s with the advent of electronic gauges, the ability to easily design tests to ensure that specific information could be obtained by use of sophisticated well test analysis software packages, and the possibility to monitor bottomhole pressure at the surface with surface pressure readout equipment. New models were also required to accommodate new testing or production procedures, such as horizontal wells (Daviau et al. 1988) and simultaneous downhole pressure and rate measurements (Kuchuk and Ayestaran 1985).

Well Test Analysis Methodology

The most significant breakthrough in well test analysis since SPE Monograph 5 (Earlougher 1977) remains the development in the late 1970s and early 1980s of a general and systematic approach to the analysis of well tests by Gringarten et al. (Gringarten et al. 1979; Gringarten 1982, 1984, 1985a, 1986). This approach unified the various techniques previously described in the literature, which had been used independently and often gave conflicting results (Ramey 1992), into a single methodology on the basis of signal theory. It pointed out inconsistencies in the way well test analyses were performed and provided answers to many fundamental questions, which today are taken for granted but were far from obvious at the time, such as

• What type of results can realistically be obtained from well testing?

• What is the best method to obtain these results?

• How does well testing actually contribute to the characterization of a reservoir as compared to other sources of information such as geophysics, geology, or petrophysics?

The Fundamental Problem of Well Testing. The emphasis of the integrated approach was on the well test "behavior," which refers to the response of the well to changes in production conditions. The behavior enables identification of the applicable well test interpretation model, which controls the maximum number of parameters that can be obtained from a test and the meaning of these parameters.

It was shown that the process to obtain the well test interpretation model was a special application of the general theory of signal analysis (Jouanna and Fras 1979). By considering well testing and well test analysis within the context of signal theory (Gringarten et al. 1979), it became easier to understand the scope and limitations of well test analysis.

In signal theory, signal processing is schematically described as (Gringarten 1985a):

$$I \rightarrow S \rightarrow O, \quad \text{(1)}$$

in which S is an operator; I, an input signal applied to S; and O, an output signal resulting from the application of I into S. O represents the dynamic response of the system S to the input signal I. Several types of problems are associated with Eq. 1, depending on which of the three quantities, I, O, or S, is unknown and must be calculated while the other two are known.

If both the input signal I and the system S are known, O can be calculated without ambiguity, and the solution is unique. This is known as the *direct problem* or convolution. An example of direct problem is as follows (Ramey 1992): The input I is (1, 2, 3), the operator S is the addition operation, the output O is 6. There is a unique answer. In well testing and petroleum engineering, this is used in forward modeling, for test design or prediction (forecasting).

Alternatively, the input signal I and the output signal O could both be known, the unknown being the system S: This is an *inverse problem*. In petroleum engineering, the inverse problem is solved during the identification of an interpretation model. Unlike the direct problem, the solution of the inverse problem is non-unique: several different systems may exist which, subjected to identical input signals, provide identical output signals. By use of the same example as for the direct problem, an inverse-problem formulation would be: The input signal I is (1, 2, 3), the output signal O is 6. What is the operator S? There is not a unique answer: It could be an addition (1+2+3 = 6) or a multiplication (1×2×3 = 6). This non-uniqueness is a property of the inverse problem that cannot be avoided. It has significant implications on the design of an efficient methodology for well test analysis.

Finally, the system S and the output signal O may be known, the unknown being the input signal I. This problem is known as *deconvolution* and also yields a non-unique answer (6 can be obtained by adding 5 and 1, 4 and 2, or 3 and 3). In well testing, deconvolution is involved when converting a variable rate drawdown pressure response into a constant-rate one.

Input and Output Signals

In well test analysis, the system S represents the unknown reservoir, the characteristics of which are to be determined. The input signal I is usually a step function in rate created by closing a flowing well or an injection well (buildup or falloff, respectively); by opening a well previously shut in (drawdown); or by injecting in a well previously closed (injection).

The corresponding output signal O is the change in pressure created by the change in rate and measured in the same well (exploration or production testing) or in a different well (interference testing). Alternatively, the input signal could be the wellhead or bottomhole pressure; the output signal would then be the change in the well production rate. In layered reservoirs, there are two output signals: the pressure, and the rates from each individual layer, which must be processed together.

A rate input signal can be created at the surface by shutting or opening the master valve or at the bottom of the well with a special downhole shut-in device. Wellhead shut-in is commonly used in wells already in production, whereas bottomhole shut-in is standard practice after drilling [a drillstem test or (DST)]. The way the rate signal is created is not important as far as well test analysis is concerned. The interpretation methods that are described hereafter are valid for both production tests and DSTs and also for the analysis of wireline formation tests. What is most important for analysis is the quality of the rate input signal, which must be of the proper shape and duration, and the quality of the measured pressure output signal.

In practice, one must differentiate between the first drawdown in a reservoir at stabilized pressure **(Fig. 2)** and a subsequent flow period **(Fig. 3).** In the first case, the output pressure signal Δp is the difference between the initial pressure p_i and the pressure $p_w(\Delta t)$ at an elapsed time Δt in the drawdown:

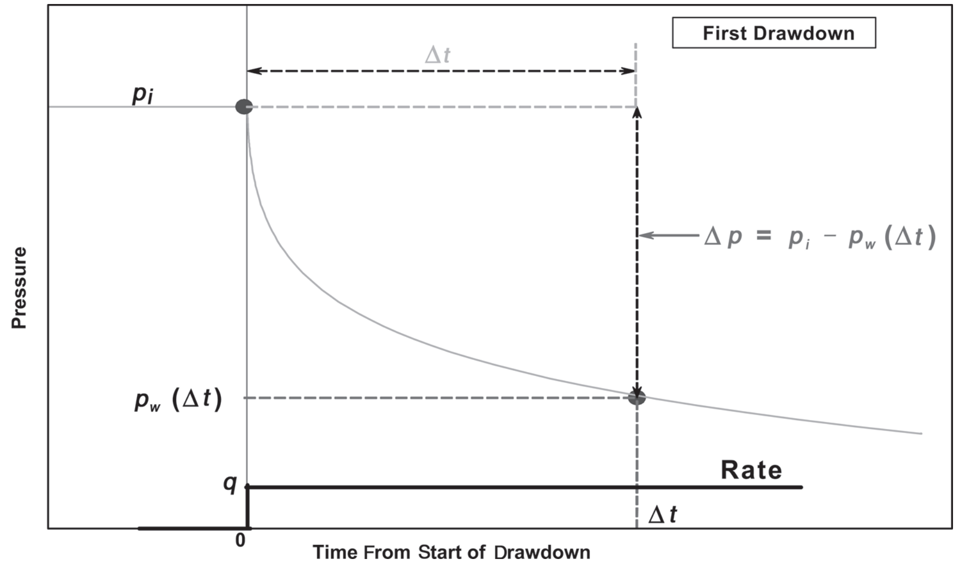

Fig. 2—Pressure response to a step rate change, first drawdown after stabilization.

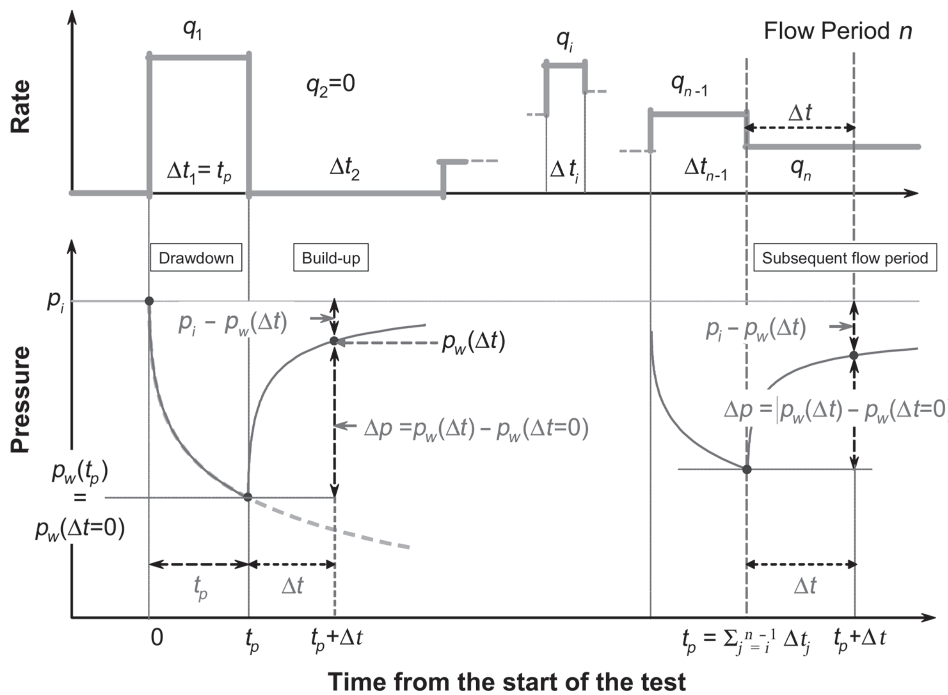

Fig. 3—Pressure response in a subsequent flow period.

$$\Delta p = p_i - p_w(\Delta t). \quad (2)$$

In the case of a subsequent flow period in a multirate test, on the other hand, there is a choice of two output signals (Fig. 3).

One can select, as before, the difference between the initial pressure p_i and the pressure $p_w(\Delta t)$ at an elapsed time Δt in the flow period of interest (Buildup Flow Period 2, or Drawdown Flow Period n in Fig. 3):

$$p_i - p_w(\Delta t). \quad (3)$$

Because p_i is usually not known, the signal is actually $p_w(\Delta t)$. This signal is analyzed with the Horner method (Horner 1951) and its extension to multirate (Odeh and Jones 1965).

Alternatively, one can select the difference between the pressure at the start of the flow period, $p_w(\Delta t = 0)$, and the pressure $p_w(\Delta t)$ at an elapsed time Δt in the flow period of interest:

$$\Delta p = |p_w(\Delta t = 0) - p_w(\Delta t)|. \quad (4)$$

This signal is analyzed by log-log analysis (Ramey 1970) and by specialized analysis (Gringarten et al. 1979).

Well Test Analysis Process. Finding the well test interpretation model involves a three-step process.

Identification of the Interpretation Model (Inverse Problem). First, one must identify a model of the actual reservoir S, say Σ, the behavior of which is identical to the behavior of S. Identical behavior in this case means that the observed output signal O obtained from the reservoir S and the output signal O' calculated from the model Σ exhibit the same qualitative characteristics (i.e., show similar shapes):

$$I \rightarrow \Sigma \rightarrow O'. \quad (5)$$

Identifying the model is the most important step of the analysis process: if the wrong model is selected, all reservoir parameters derived from the analysis will be incorrect, and the subsequent engineering decisions on the basis of these parameters will likely be inappropriate. For instance, mistaking a double porosity behavior for a depletion effect (which was not uncommon before type-curve analysis and derivatives became available) has led operators to abandon wells that were perfectly viable.

Finding Σ implies solving the inverse problem, which requires an identification or pattern-recognition process. By definition, the solution is not unique. The degree of non-uniqueness tends to increase with the complexity of the reservoir behavior and to decrease with the amount of information available on the well and reservoir being tested. One must therefore try to reduce the non-uniqueness of the solution by using as much information as possible. In practice, this means:

- Increase the amount and quality of input and output information used directly in the analysis (i.e., the amount and quality of both rate and pressure-test data).
- Perform a series of specifically designed verification tests on the model.
- Verify the consistency of the well test interpretation model with additional, nontesting information from geophysics, geology, petrophysics, drilling, production logging, etc.

The need for more complete pressure and rate test data has not always been obvious, although it is clear from Eq. 2 that both pressure and rate information are required for signal processing. This is because at any given time, the understanding of the interpretation process and the limitations of measuring devices dictate the requirement for data. Measuring devices and data-acquisition requirements in turn tend to be limited to the needs of the dominant analysis techniques. Progress in measurement devices and test design usually takes place only when new interpretation techniques are developed that require new measurements. For many years, emphasis mainly has been on pressure-buildup data. Rates often were reported only as average wellhead values before the buildup. New advanced techniques now require drawdown pressure data as well as buildup data and accurate flow rates as a function of time. In the same way, early-time pressure data either were not measured or were not read from recorder charts until required by the early-time analysis techniques discussed in SPE Monograph 5 (Earlougher 1977). Accurate measurement of these data was made possible by the subsequent development and routine use of electronic gauges. Now, the current trend is toward longer tests, helped by downhole permanent pressure gauges, to take advantage of new interpretation models that enable identification of heterogeneities and boundary effects in the reservoir away from the wellbore.

It must be stressed that non-uniqueness is not specific to well test analysis. All interpretation and modeling processes give non-unique answers. This holds true in geophysical interpretation, in geological interpretation, in log interpretation, and in the reservoir modeling aspect of reservoir simulation. The problem of non-uniqueness is now well recognized in the oil industry. It is the main reason for the increasing use of stochastic modeling techniques, which aim at providing alternative equi-probable representations of the reservoir to capture the uncertainty associated with predictions (Hewett 1986; Suro-Perez et al. 1991).

In identifying a well test interpretation model from well test data, we are not limited by our ability to mathematically represent interpretation models, either analytically or numerically (i.e., by our ability to solve the direct problem), but by our ability to solve the inverse problem (i.e., by the current state-of-the-art techniques in model identification). As identification techniques become more powerful [as with derivatives (Bourdet et al. 1983a) and deconvolution (von Schroeter et al. 2001)] and the resolution of measurements improves, the number of behavior components that can be identified increases, resulting in more-detailed interpretation models.

Calculation of the Interpretation Model Parameters (Direct Problem). Once the interpretation model has been identified, its response must be generated (either analytically or numerically), and the parameters of the model must be adjusted until the model gives the same quantitative response as the actual reservoir. This is in addition to providing the same qualitative response (e.g., same shape), a condition that controlled the selection of the model in the first place. The adjusted numerical values of the model parameters are then said to represent the values of the corresponding reservoir parameters.

At this stage of the interpretation process, the problem to be solved is the direct problem, because the model is now known. Because the solution of the direct problem is unique, there is a unique set of model parameter values that can provide a best fit with the observed data. This means that once the interpretation model is selected, the reservoir parameters corresponding to that model are defined uniquely, and the numerical values of these parameters are independent of the method used to calculate them. Results must be the same whether reservoir parameters are calculated by use of straight lines, log-log type-curve matching, or nonlinear regression techniques (Rosa and Horne 1983). The only acceptable differences are those caused by the differences in resolution of the various methods.

In other words, different interpretation methods that use the same interpretation model must produce the same parameter values when applied properly. This was not universally understood before the development of the integrated methodology, because straight-line methods [MDH (Miller et al. 1950) and Horner (1951)] and type-curve analysis—with different type curves representing the same model (Agarwal et al. 1970; McKinley 1971)—often gave different results.

Verification of the Interpretation Model. Because of the nonuniqueness, one must verify the interpretation model found during the identification step. Consistency checks are made among all characteristics inferred by the model and the corresponding known information from the actual reservoir and measured data. If the model satisfies all the checks, it is deemed to be “consistent” and to represent a valid solution to the problem. If the model fails any check, it is considered invalid.

The interpretation process must be repeated to identify all possible consistent models, which can be ranked in terms of decreasing probability. If needed, a new well test can then be designed to confirm the most probable model.

Well Test Interpretation Model

One important ingredient of the integrated methodology was the realization from experience that although reservoirs are different in terms of physical description (type of rock, depth, pressure, size, type of fluid, fluid content, etc.), the number of possible dynamic behaviors of these reservoirs during a well test are limited. This is because a reservoir acts as a low-resolution filter so that only high contrasts in reservoir properties can appear in the output signal (Perez-Rosales 1978). Furthermore, these dynamic behaviors are obtained from the combination of three components (Gringarten et al. 1979; Gringarten 1982, 1985a) that dominate at different times during the test, namely

- The basic dynamic behavior of the reservoir during middle times, which is usually the same for all the wells in a given reservoir
- Near-wellbore effects at early times resulting from the well completion that may vary from well to well or from test to test
- Boundary effects at late times, determined by the nature of the reservoir boundaries, which is the same for all the wells in a given reservoir, and by the distance from the well to these boundaries, which may differ from well to well

Basic Reservoir Behaviors. The basic reservoir dynamic behavior reflects the number of porous media of different mobilities (kh/μ) and storativities ($\phi c_t h$) that participate in the flow process (Gringarten 1984, 1986). These basic well test behaviors are illustrated in **Fig. 4.**

Homogeneous Behavior. If there is only one mobility and one storativity involved, the behavior is called “homogeneous.” Homogeneous behavior means that variations in mobility (kh/μ) and storativity ($\phi c_t h$) throughout the reservoir are too small to be seen in well test data. In terms of flow, there is essentially only one single porous medium. As a result, the permeability measured in a test corresponds to the same permeability system as that described by core data. The respective values of permeability could be different, but only because the conditions of the measurements are different. Although uniformly homogeneous properties are assumed in the derivation of the analytical representations of the interpretation model from the diffusivity equation, the word “homogeneous” associated here to the word “behavior” does not imply that the actual reservoir has homogeneous properties throughout.

Heterogeneous Behavior. “Heterogeneous” behavior, on the other hand, means two or more mobilities and storativities are interacting. These may be uniformly distributed or segregated, but their main characteristic is that their values are noticeably different.

One example of heterogeneous behavior is the double-porosity behavior (Warren and Root 1963). Double-porosity behavior involves two media with widely different permeabilities, and only the most permeable medium can produce fluid into the well. The other acts as a recharge for that most permeable medium. Double-porosity behavior combines two successive homogeneous behaviors, which only differ by their porosities—or more correctly, by their storativities. The first homogeneous behavior is controlled by the mobility and storativity of the most permeable porous medium at early middle-times. The second homogeneous behavior is controlled by the same mobility and the sum of the storativities of the constitutive media at late middle-times. Double-porosity behavior occurs generally in naturally fractured reservoirs, in multilayered reservoirs with high permeability contrast between the layers, and in single-layered reservoirs with high permeability variation along the reservoir thickness. Double-porosity behavior is typically found in carbonate reservoirs, and in carbonate, limestone, granite, basalt, and unconsolidated sand formations (Gringarten 1984).

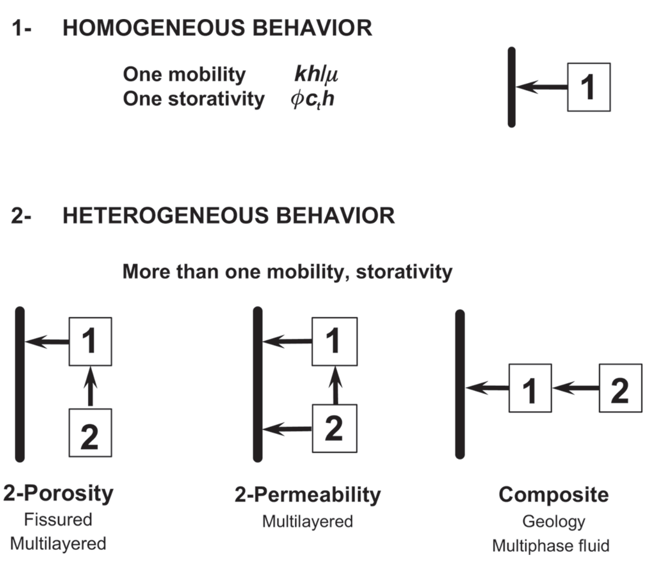

Fig. 4—Basic well test interpretation-model reservoir behaviors.

Another example of heterogeneous behavior is the double-permeability behavior (Bourdet 1985), which refers to two distinct porous media as in double porosity, but each medium can produce into the well. Examples of double-permeability behavior can be found in multilayered reservoirs with relatively low permeability contrast between the layers. Commingled reservoirs are a special case of double-permeability behavior with no interlayer crossflow. Contrary to homogeneous behavior, double-porosity and double-permeability behaviors imply that the permeability measured in a test and the permeability measured in a core may correspond to different porous media.

A third example of heterogeneous behavior is the composite behavior, which implies one set of mobility and storativity values around the well and a different one at some distance from the well. Composite behavior may be caused by a change in reservoir thickness or porosity, a variation of facies, or a change in fluid mobility in the reservoir. Examples of composite behaviors are found in such circumstances as low-permeability oil reservoirs when pressure around the wellbore drops below the bubblepoint pressure, in low-permeability gas condensate reservoirs when pressure is less than the dewpoint pressure (Chu and Shank 1993), in carbonate reservoirs after acidification, and in oil reservoirs surrounded by an aquifer.

Near-Wellbore and Outer-Boundary Effects. To be complete, a well test interpretation model must include the applicable near-wellbore and reservoir outer-boundary effects in addition to the basic reservoir behaviors. As with basic behaviors, the number of possibilities is limited. They are listed in **Fig. 5.**

The near-wellbore conditions include wellbore storage (Van Everdingen and Hurst 1949; Ramey 1970), skin effect (Van Everdingen 1953; Hurst 1953), a single (usually hydraulic) fracture (Russell and Truitt 1964; Gringarten et al. 1975; Cinco-Ley et al. 1978; Agarwal et al. 1979), partial penetration or limited entry (Brons and Marting 1961), and a horizontal well (Reiss and Giger 1982).

Outer boundaries can be of three types: prescribed rate (e.g., no flow as in the case of a sealing fault), prescribed pressure (e.g., for instance, constant pressure, as in the case of a gas cap or an active aquifer) or leaky (i.e., semipermeable), as in the case of a non-sealing fault. No-flow and constant-pressure boundaries can also be created in a developed reservoir by near-by production or injection wells, respectively. Because of the low resolution of the well test signals currently available, it is difficult in some cases to obtain much detail on the shape of the boundaries from well test analysis. For instance, it is difficult to distinguish a circular reservoir from a square reservoir with the same area when the well is at the center. Boundaries that can be diagnosed in the horizontal direction with current well test analysis techniques are single linear faults, intersecting faults (wedges), parallel faults (channels), open rectangles (i.e., three boundaries intersecting at right angles), rectangular reservoirs, or circular reservoirs. In each case, distinction can be made with reasonable confidence between constant pressure and no flow. Leaky conditions can also be identified if the test is long enough (Yaxley 1987). Nonrectangular boundaries and meanders in fluvial channels can also be seen in well test data (Zambrano et al. 2000; Mijinyawa and Gringarten 2008).

In addition, the boundary type in the vertical direction can be identified if the well is partially penetrating or horizontal. This includes a constant-pressure upper-boundary effect caused by a gas cap or a constant lower-pressure boundary effect resulting from an active bottomhole waterdrive.

The Complete Interpretation Model. The complete interpretation model is made of the combination of the individual components described above. Although the number of interpretation model components are limited (five near-wellbore effects, two basic reservoir behaviors, and three types of outer-boundary effects), their combination can yield several thousand different interpretation models to match all observed well behaviors.

The challenge of the well test interpreter is to diagnose from the observed well behavior which of the components described above should be included in the interpretation model. This is achieved by identifying the flow regimes associated with these components. The identification process relies on the fact that these various flow regimes (linear, bilinear, spherical, radial, etc.) yield different transient pressure behaviors during a test and occur at different times. A schematic of the complete interpretation process is shown in **Fig. 6.**

Evolution of Well Test Analysis Methods

The extent to which the identification process of Fig. 6 can be performed effectively is a direct function of the analysis techniques being used and particularly of their ability to diagnose and verify an interpretation model efficiently (Gringarten 1987). This is summarized in **Fig. 7.**

In terms of diagnosis and verification, the derivative method is much better than the log-log pressure type-curve matching method. Both are significantly better than the straight-line techniques, especially if they are performed with software that can generate the model directly rather than relying on matching with published type

NEAR-WELLBORE EFFECTS	RESERVOIR BEHAVIOR	BOUNDARY EFFECTS
Wellbore storage Skin Fractures Partial penetration Horizontal well	Homogeneous Heterogeneous • 2-Porosity • 2-Permeability • Composite	Specified rates Specified pressure Leaky boundary
EARLY TIMES	MIDDLE TIMES	LATE TIMES

Fig. 5—Components of the well test interpretation model.

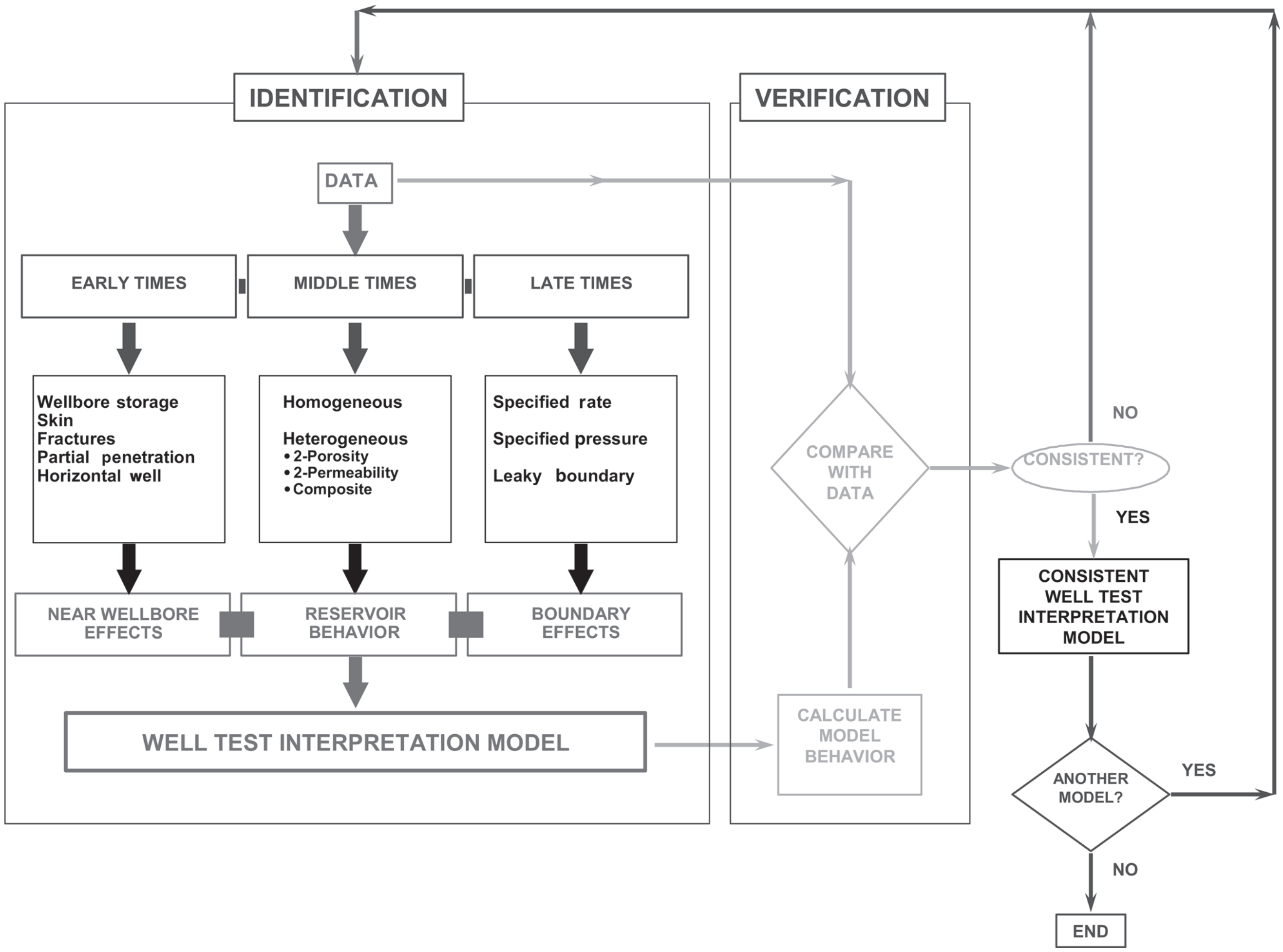

Fig. 6—Well test interpretation-model identification process.

curves. Specifically, the straight-line techniques, although simple to use, are poor at selecting the very straight lines on which they are to be applied. And once a straight line has been selected, there is no rule to indicate if it is indeed the right one, (i.e., the one corresponding to the flow regime being analyzed). This is why, when powerful personal computers became available, the derivative approach superseded log-log pressure analysis, which before had superseded straight-line techniques.

	ANALYSIS METHOD	IDENTIFICATION	VERIFICATION
50s	Straight lines	Poor	None
70s	Pressure type curves	Fair (limited)	Fair to good
80s	Pressure derivative	Very Good	Very good
00s	Deconvolution	Much better	Same as derivative
Next	?	>>>	>>>

Fig. 7—Ranking of well test interpretation methods.

Identification has also greatly improved recently with the development of a stable algorithm for deconvolution (von Schroeter et al. 2001). By converting pressure at variable rate into pressure at constant rate, deconvolution transforms a test into a single drawdown with a duration equal to that of the test, thus increasing the amount of data that can be analyzed with “conventional” analyses. The gain is clearly greater in long tests, such as with permanent downhole pressure gauges, in which the total test duration is one or two orders of magnitude greater than the duration of the longest flow period at constant rate. Deconvolution, however, is also useful in short tests such as DSTs because it increases the radius of investigation and enables differentiation between true test behavior and artifacts of the derivative calculation.

Fig. 7 also provides a clear direction for future development in well test analysis. Any further improvement in interpretation technology can come only from further significant improvements in the identification and validation steps. Any new method that does not achieve these goals is unlikely to have a lasting impact on well test analysis technology (Blasingame et al. 1989; Onur and Reynolds 1988; Duong 1989).

Straight-line Analyses. Straight-line analysis techniques rely on the existence of a straight line on a plot of the pressure response vs. some function of the elapsed time when a particular flow regime dominates **(Fig. 8).** The straight-line slope and intercept provide the well and reservoir parameters that control this flow regime. To identify the complete interpretation model, straight-line analyses must be applied to all the flow regimes present in the pressure behavior.

Straight-line analyses include “specialized” analysis methods (Gringarten et al. 1979; Gringarten 1985a) based on the signal defined by Eq. 4 and superposition analyses (Odeh and Jones 1965) based on the signal defined by Eq. 3. In specialized plots, the change in pressure during a given flow period, Δp from Eq. 4, is plotted against a flow regime-specific function of the elapsed time, $f(\Delta t)$, on a Cartesian graph. $f(\Delta t)$ comes from the equations describing the various flow regimes. It is equal to: Δt for wellbore storage (Ramey 1970) and pseudosteady-state flow in closed reservoirs (Jones 1956), $\sqrt{\Delta t}$ for high-conductivity fracture (Clark 1968) and channel linear flows (Miller 1962; Millhein and Cichowicz 1968), $\sqrt[4]{\Delta t}$ for low-conductivity fracture and bilinear flow (Cinco-Ley and Samaniego 1981), $1/\sqrt{\Delta t}$ for spherical flow (Moran and Finklea 1962), and $\log(\Delta t)$ for radial flow in reservoirs of infinite extent (Miller et al. 1950) or bounded by a sealing fault (Horner 1951) or by two no-flow intersecting faults (van Pollen 1965; Prasad 1975).

Horner and superposition analyses, on the other hand, require $\Delta p(\Delta t)$ to be plotted against a flow-regime-specific superposition time (also called generalized Horner time):

$$\sum_{i=1}^{n-1} \left[(q_i - q_{i-1})/(q_{n-1} - q_n)\right] f\left(\sum_{j=1}^{n-1} \Delta t_j + \Delta t\right) - f(\Delta t), \qquad (6)$$

on a Cartesian plot. $f(\Delta t)$ is the same as for specialized analyses. Horner and superposition plots cannot be used if $f(\Delta t)=\Delta t$ (i.e., for wellbore storage and pseudosteady-state flow). The permeability-thickness product is obtained from the radial-flow regime straight-line slope (Miller et al. 1950; Horner 1951), whereas the skin effect is obtained from the intercept. The shapes of the data also provide information on the skin: Pressure data reach the straight line from below in damaged wells and from above in stimulated wells (Miller et al. 1950). The main advantage of the straight-line methods is their ease of implementation, because they were designed through simplifying assumptions to be performed with only a piece of graph paper, a pencil, a ruler, and simple calculations.

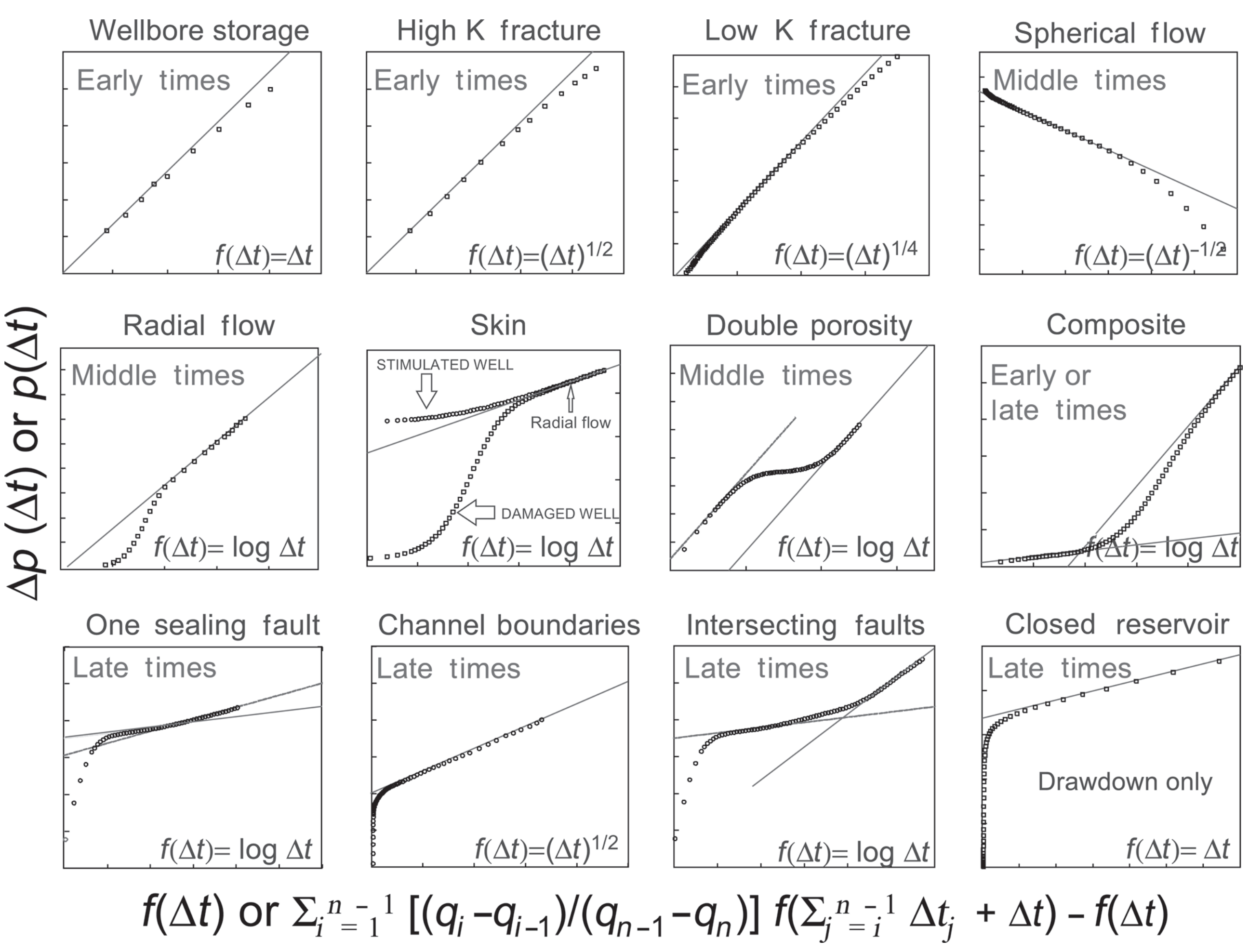

Fig. 8—Straight-line analyses.

Specialized plots are the easiest to use, followed by Horner plots. Superposition was usually considered too cumbersome to be done by hand until off-the-shelf well test analysis software became available on personal computers in the mid-1980s. Until then, straightline methods were routinely applied only to the analysis of the radial flow regime in buildups [the corresponding MDH (Miller et al. 1950) and Horner (1951) analyses were the main emphasis of SPE Monograph 1 (Matthews and Russell 1967)]. All flow periods before the buildup being analyzed in a multirate test had to be approximated by a single drawdown with a duration equal to:

$$t_{pe} = 24V_p/q, \quad (7)$$

in which t_{pe} is the "equivalent" Horner production time, V_p, the cumulative production since the last pressure equalization, and q the last rate before the buildup [such an approximation introduces significant errors in the analysis (Horner 1951), as discussed later in this paper]. Eq. 6 then reduces to the radial-flow Horner time for the case of a single drawdown of duration t_p followed by a buildup:

$$\log \frac{t_p + \Delta t}{\Delta t}. \quad (8)$$

The main limitation of straight-line techniques is their inability to identify with confidence the proper straight line to be used in an analysis, as indicated in Fig. 7. An apparent straight line through a set of data does not prove the existence of a specific flow regime, and if the selected straight line is not a real straight line or is a straight line corresponding to a different flow regime from that expected, an analysis on the basis of that straight line would yield erroneous results. Consequently, straight lines cannot be used with confidence to identify an interpretation model. The knowledge of the applicable interpretation model is actually required to identify the straight lines usable for analysis.

An additional problem, which affects specialized plots only, is illustrated in **Fig. 9.** It shows a radial-flow specialized plot [MDH (Miller et al. 1950)] for a buildup following an initial constant rate drawdown of duration t_p. Although radial flow in this example starts at Δt=5 hours and lasts through the end of the buildup at Δt= 72 hours, the corresponding buildup points are on the radial flow straight line if t_p =720 hours only. For smaller values of t_p, buildup data first follow the radial flow semilog straight line, then fall below it. The time during which the semilog straight line exists through the pressure points (the "length" of the straight line) is clearly a function of the production time. The reason is that specialized analyses strictly apply only to the initial drawdown in a stabilized reservoir (Gringarten et al. 1979). They also can be used in a subsequent flow period, as long as the elapsed time in the flow period being analyzed is small compared with the duration of the previous flow period. If this is no longer the case, data points deviate from the straight line even though the flow regime of interest still dominates. The risk for an interpreter is that the later part of the data set can be (and often is) mistaken for the MDH straight line (Ramey and Cobb 1971), thus yielding erroneous analysis results.

This problem does not exist with Horner and superposition plots, because the only condition for the existence of a straight line for a given flow regime is that data exist within the range of validity of the corresponding flow regime. As shown in Fig. 9, there is no restriction on the magnitude of the production time t_p. Because of the production time dependency, specialized plots are mainly used for the analysis of near-wellbore effects, whereas Horner and superposition analyses are used for reservoir behavior and boundary effects.

Log-Log Pressure Analysis. Type-curve or log-log analysis methods were introduced in the petroleum literature by Ramey (1970) in an attempt to overcome the limitations of straight-line-based analysis methods (Matthews and Russell 1967; Earlougher 1977). The initial objective was to identify the correct infinite-acting radial-flow straight line on an MDH (Miller et al. 1950) or a Horner (1951) semilog plot and to permit analysis of test data when such a radial-flow straight line had not yet been produced (Ramey 1970). Log-log analysis was subsequently expanded into a process for identifying the various components of the interpretation model (Gringarten et al. 1979; Bourdet and Gringarten 1980).

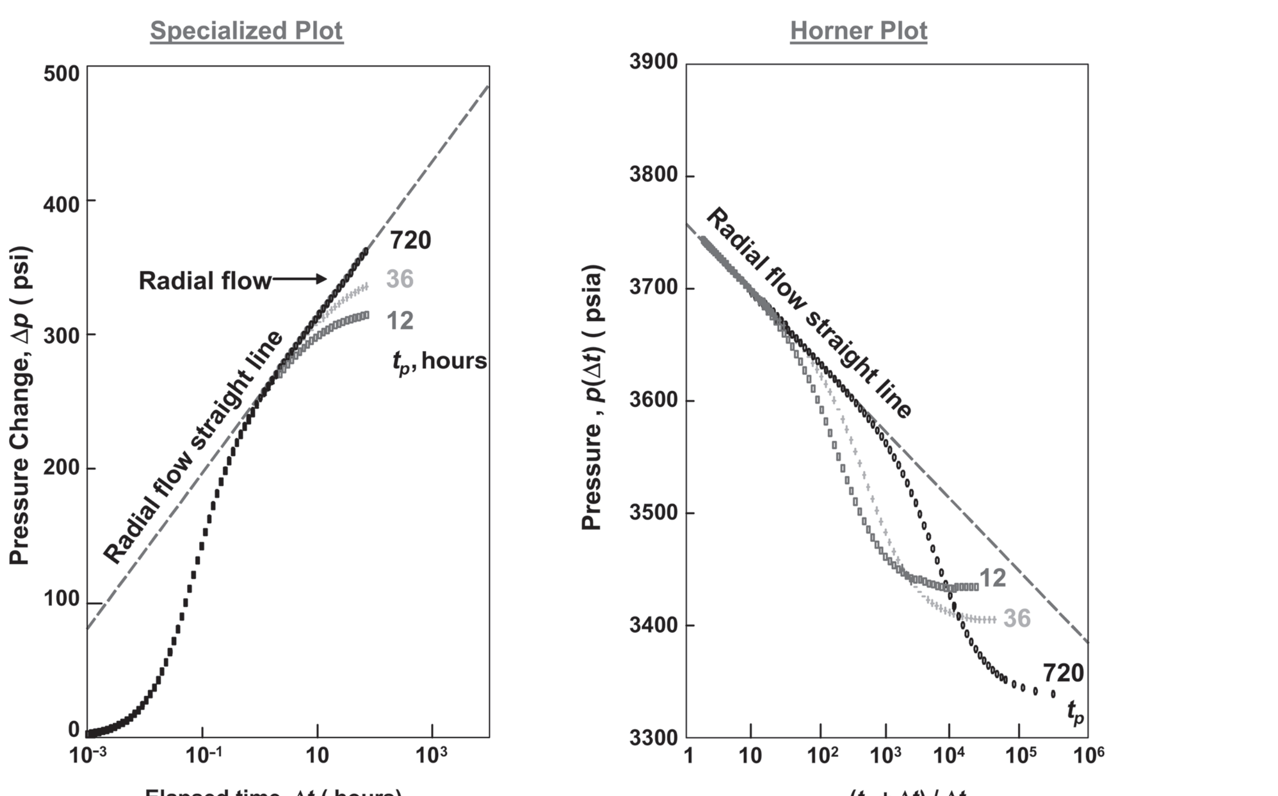

Fig. 9—Specialized vs. Horner plots.

Although the type-curve method had been introduced as supplementary to straightline techniques (Ramey 1970), there was much arguing in the well testing literature from the early 1970s to the mid-1980s about the relative merits of the two approaches. A number of interpreters were confused by the lack of a clear methodology on how to select the "right" type curve among the many that were published during that time (Agarwal et al. 1970; McKinley 1971; Earlougher and Kersh 1974; Gringarten et al. 1975; Cinco-Ley and Samaniego 1978) and by the fact that different type curves published by different authors (Agarwal et al. 1970; McKinley 1971) for the same wellbore storage case often gave different results when applied to the same data (Ramey 1980). The controversy even led to an early SPE board decision (Ramey 1992) not to include full-scale type curves in the Earlougher SPE Monograph 5 (Earlougher 1977), and it was recommended in Monograph 5 that type-curve analysis be only used in an emergency or as a checking device after "conventional" (i.e., straight-line) methods had failed. After the systematic approach to the analysis of well tests was established (Gringarten et al. 1979; Gringarten 1982, 1985a, 1986), the differences among published wellbore storage type curves (Agarwal et al. 1970; McKinley 1971; Earlougher and Kersh 1974) were explained (Gringarten et al. 1979), an industry-standard type curve emerged for wellbore storage and skin (Gringarten et al. 1979), and the early SPE board decision was reversed.

For the purpose of log-log analysis, the change in pressure during a given flow period in the test, Δp from Eq. 4, is plotted vs. the elapsed time, Δt, on a log-log graph. Such a graph scales Δp and Δt in exactly the same way for both interpretation model and field data and is the only graph to do so. It permits model identification by emphasizing characteristic shapes for different flow regimes **(Fig. 10).** For this reason, a log-log plot is called a diagnostic plot (Gringarten et al. 1979). Because the constitutive flow regimes are also associated with specialized and superposition plots, log-log diagnostic plots and specialized or superposition plots can be used together to identify and verify the various flow regimes that dominate during a test (Ramey 1970; Gringarten et al. 1979).

Although quite powerful compared with straight-line methods, identification from log-log pressure analysis has its limitations. In particular, the lack of resolution in pressure change makes it difficult to diagnose flow regimes that occur at late times. Even early-time and middle-time flow regimes cannot be identified easily if they do not yield a log-log straight line. This is illustrated in Fig. 10. Fig. 10 shows the log-log shapes of the various flow regimes that can be identified by log-log analysis in the case of the first drawdown in a stabilized reservoir. Although mostly theoretical, this case yields the true log-log characteristics of the flow regimes, whereas subsequent flow periods are affected by the rate history (Raghavan 1980) in the same way specialized plots are (Gringarten et al. 1979).

Wellbore storage yields a straight line of unit slope (i.e., one log cycle Δp, for one log cycle Δt) (Ramey 1970) at early times, because Δp is proportional to Δt (Van Everdingen and Hurst 1949). A high-conductivity fracture communicating with the wellbore exhibits an early-time log-log straight line of half-unit slope (one log cycle Δp for two log cycles Δt), because Δp is proportional to the square root of Δt during 1D flow from the matrix into the fracture (Clark 1968). A low-conductivity fracture yields a quarter-unit slope (one log cycle Δp for four log cycles Δt) (Cinco-Ley and Samaniego 1981), which corresponds to bilinear flow in the fracture. On the other hand, other possible near-wellbore effects cannot be identified because of the lack of resolution in the pressure change. Partial penetration with positive mechanical skin, for instance, is undistinguishable from a damaged, fully penetrating well (Kuchuk and Kirwan 1987).

Radial flow is also difficult to diagnose because it does not yield a straight line. It instead exhibits a nondescript log-log shape, which corresponds to the linear relationship between Δp and $\log(\Delta t)$ (Van Everdingen and Hurst 1949) characteristic of that flow regime. Heterogeneous behavior yields an S-shaped curve, which corresponds to two distinct homogeneous behaviors separated by a transition period, a characteristic of heterogeneous systems. In practice, only double-porosity behavior (Bourdet and Gringarten 1980) can be identified.

In general, boundary effects are difficult to identify except for constant-pressure boundaries and closed systems from drawdown data, which respectively show a stabilization or become asymptotic to a unit slope log-log straight line at late times [Δp is a linear function of Δt (Jones 1956)].

The main limitation of pressure type-curve analysis comes from its use as a manual process before well test analysis software became available. Once the interpretation model had been identified, the data were matched with a dimensionless type curve representing the model behavior, following the matching procedure described in SPE Monograph 5 (Earlougher 1977). Log-log analysis then yields all the model parameters, the values of which could then be compared with those obtained from individual straight-line

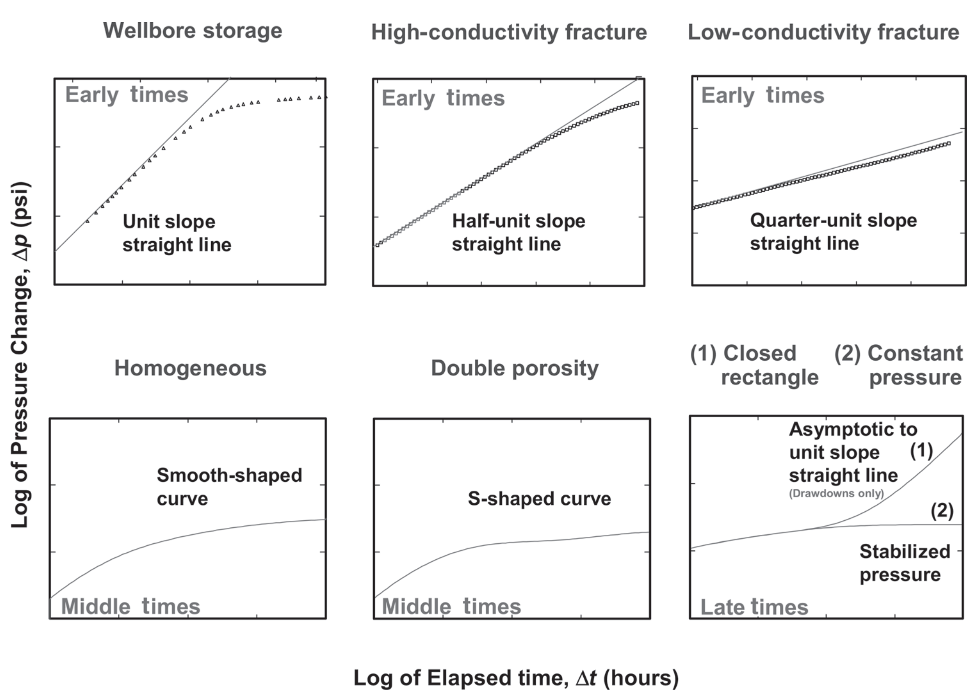

Fig. 10—Flow regime log-log pressure shapes.

analyses. There were, however, only a limited number of published type curves, covering a limited number of combinations of near-wellbore effects, reservoir behaviors, and outer boundaries. In addition, most published type curves, for the sake of simplicity, were valid only for the first drawdown after full stabilization of the reservoir pressure. Finally, experience showed that contrary to early expectations (Ramey 1980), pressure type-curve matching usually was non-unique for a given model if radial flow had not been not reached during the flow period of interest (Ramey 1992).

Log-Log Derivative Analysis. Pressure-derivative functions have been mentioned at various times in the petroleum literature (Van Everdingen and Hurst 1949; Jones 1956; Carter and Tracy 1960; Ramey 1965; van Pollen 1965; Agarwal et al. 1965; Gringarten and Ramey 1971; Lescaboura et al. 1975), in connection with water influx (Van Everdingen and Hurst 1949; Carter and Tracy 1960; Agarwal et al. 1965), interference testing (Lescaboura et al. 1975), reservoir boundaries (Jones 1956; van Pollen 1965), and wellbore storage calculations (Van Everdingen and Hurst 1949; Ramey 1965). Applications to well test analysis first appeared in the late 1970s: A log-log plot of $d\Delta p/d(\Delta t)$ vs. Δt was suggested as an alternative to straight-line analyses for interference tests (Tiab and Kumar 1980a), tests in fractured wells (Tiab and Puthigai 1988), and tests in reservoirs bounded by two parallel faults (Tiab and Kumar 1980b) and by multiple faults (Tiab and Crichlow 1979). The advantage of using a derivative on the basis of the natural log of elapsed time, $d(\Delta p)/d(\log\Delta t)$, which emphasizes radial flow, was also demonstrated for the description of heterogeneous reservoirs (Perez-Rosales 1978). The practicality and power of the derivative approach for well test interpretations, however, was recognized only after the 1983 publications by Bourdet et al. (1983a, 1983b) of derivative type curves expressed in terms of independent variables for both homogeneous (Gringarten et al. 1979) and double-porosity interpretation models (Bourdet and Gringarten 1980). Taking the derivative with respect to the natural log of Δt emphasizes radial flow, which is the most common flow regime around a well and yields a stabilization while radial flow dominates. The derivative could be taken with respect to a different flow regime to yield a stabilization when that flow regime dominates. For instance, the derivative with respect to Δt yields a stabilization during wellbore storage at early times and during pseudosteady-state flow at late times.

The major advantage of pressure derivative is that it has greater diagnosis and verification capabilities than the change in pressure itself with the accuracy of straight-line methods. Derivative shapes for various flow regimes at early, middle, and late times in a test are displayed in **Fig. 11** for $d(\Delta p)/d(\ln\Delta t)$. When wellbore storage dominates, the pressure derivative is proportional to the elapsed time and is identical to the change in pressure. Consequently, when Δp and $d(\Delta p)/d(\ln\Delta t)$ are plotted on the same log-log graph, they share the same unit slope log-log straight line at early times. Damaged wells exhibit a maximum at early times, following the wellbore storage unit slope straight line (the higher the skin, the higher the maximum). Nondamaged or stimulated wells, on the other hand, show a small maximum or no maximum at all. In case of a high-conductivity fractured well, the early-time-derivative response is proportional to the square root of time. On a log-log plot, the derivative response follows a half-unit slope straight line (Alagoa and Ayoub 1985). The amplitude of the derivative response is half that of the pressure change. When both pressure and derivative curves are plotted on the same log-log graph, the two early-time straight lines are parallel and are vertically displaced by a factor of two. For a low-conductivity fracture, during bilinear flow at early times, the derivative response is proportional to the fourth root of time and exhibits a straight line of one-quarter unit slope on a log-log plot (Wong et al. 1986). The amplitude of the derivative response is one-fourth that of the pressure change. During partial penetration or limited-entry spherical-flow behavior, the derivative response is proportional to the inverse of the square root of time (Moran and Finklea 1962; Culham 1974; Raghavan and Clark 1975; Kohlhaas et al. 1982). On a log-log plot, this yields a straight line with a negative half-unit slope.

Radial flow yields a stabilization (Perez-Rosales 1978; Bourdet et al. 1983a), which is inversely proportional to the dominant mobility kh/μ: the higher the stabilization level, the lower the mobility. A change in mobility resulting from heterogeneous behavior is characterized by two stabilizations on the derivative. A second stabilization at a higher level than the first one indicates a decrease in mobility, whereas a stabilization at a lower level denotes a mobility increase (Tiab and Crichlow 1979). A change of storativity, on the other hand, yields a maximum or a minimum between the initial and final stabilizations. A maximum is obtained when storativity decreases—a minimum, when storativity increases.

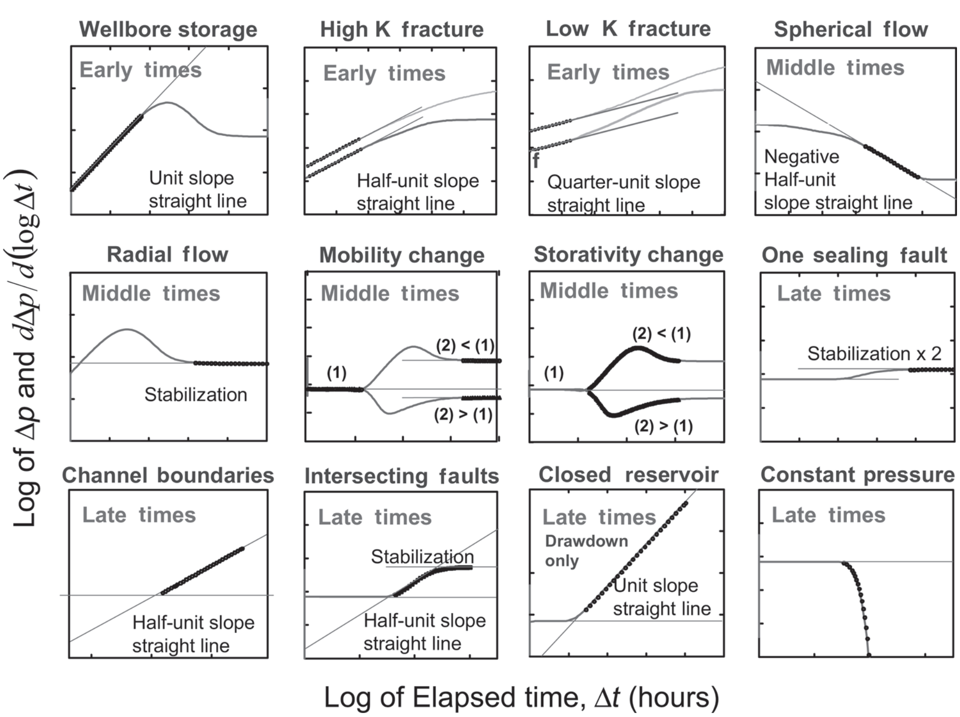

Fig. 11—Flow-regime log-log derivative shapes.

The derivative for a sealing fault yields a late-time stabilization at a level equal to twice that for infinite acting radial flow (Clark and Van Golf-Racht 1985). A channel configuration produces a late-time half-unit slope straight line. Such a straight line appears immediately after the homogeneous infinite-acting radial-flow stabilization if the well is equidistant from the two parallel boundaries. If the well is closer to one of the boundaries, it is preceded by a second stabilization at twice the level of the first one. When two faults intersect, the derivative shows a late-time stabilization at a level equal to $2\pi/\theta$ (van Pollen 1965; Prasad 1975) times the radial-flow stabilization level, in which θ is the wedge angle in radians. This final stabilization is preceded by a half-unit slope log-log straight line. During pseudosteady-state behavior in a closed reservoir, the drawdown pressure derivative exhibits a late-time log-log straight line of slope unity (Clark and Van Golf-Racht 1985). This line is reached faster by the derivative than by the pressure (Fig. 10) because the slope of the derivative is identically unity, while the slope of the pressure drop is only approximately unity. In the case of a constant-pressure boundary, on the other hand, the derivative tends to zero (Clark and Van Golf-Racht 1985) while Δp stabilizes. The rate of decline of the derivative curve depends on the shape of the boundary and is faster for a circular constant-pressure boundary than for a linear constant-pressure boundary.

Once an interpretation model has been identified, well and reservoir parameters are obtained by matching the pressure derivative for that interpretation model with the derivative of the field data. As with pressure data, the match can be performed numerically or manually using a derivative type curve for the applicable interpretation model. The change in pressure must be matched at the same time to calculate the skin effect because the derivative is not very sensitive to that parameter. For some flow regimes, parameters can be obtained directly from the derivative for these flow regime, without matching with a complete model. For instance, the permeability thickness product can be calculated directly from the radial flow stabilization line, and the wellbore storage can be obtained from the intersect of the radial flow stabilization and the unit-slope wellbore storage lines (Gringarten 1985b). The same procedure can be applied to other flow regimes (Tiab 1989, 1993a, 1993b; Tiab et al. 1999).

The main drawback of derivatives is that, contrary to pressure data, they are not measured but must be calculated. Their usefulness therefore depends on how well they are computed. The various derivative shapes shown in Fig. 11 assume that the data are from an initial, constant-rate drawdown in a new reservoir with no prior production history. In practice, this is never the case, and the derivative must be taken with respect to the superposition time of Eq. 6 with $f(\Delta t)=\log(\Delta t)$ to avoid the influence of the production time on the length of the radial flow stabilization (Bourdet et al. 1983a; Bourdet et al. 1989) (multirate derivative). This transforms the derivative of pressure data from a subsequent flow period into an equivalent first-drawdown derivative except when the end of the previous flow period is not in radial flow. Then, the multirate derivative may differ from the drawdown derivative (Clark and Van Golf-Racht 1985) **(Fig. 12)** depending on the previous rate history [the multirate derivative follows a transition from the drawdown-first derivative to the drawdown-second derivative (Cinco-Ley et al. 1986; Cinco-Ley and Samaniego 1989)]. The interpreter must be careful not to misinterpret this deviation for a flow regime behavior (Gringarten 2005).

The multirate derivative also differs from the first drawdown derivative in buildups in closed reservoirs under pseudosteady-state flow. Because of depletion, the pressure tends to stabilize to the average reservoir pressure, and buildup derivatives tend to zero, whereas derivatives in drawdowns yield a unit-slope log-log straight line.

It must be stressed that that the multirate derivative, although taken with respect to the superposition time, must be plotted as a function of the elapsed time. Some well test analysis software routinely plots the multirate derivative vs. an equivalent time, defined as (Agarwal 1980):

$$t_{\text{eff}} = \frac{t_{pe}\Delta t}{t_{pe} + \Delta t}, \quad (9)$$

or its multirate equivalent. The equivalent time was introduced by Agarwal (1980) to convert buildup data into equivalent drawdown data so that they could be matched with published drawdown type curves. To work, the equivalent time required radial flow to have been reached before the buildup being analyzed. When applied to derivatives, the equivalent time creates distortions that makes identification of flow regimes more difficult and can be misinterpreted for reservoir behaviors **(Fig. 13).**

The first drawdown derivative and the multirate derivative are proportional to the slope of the MDH and superposition plots,

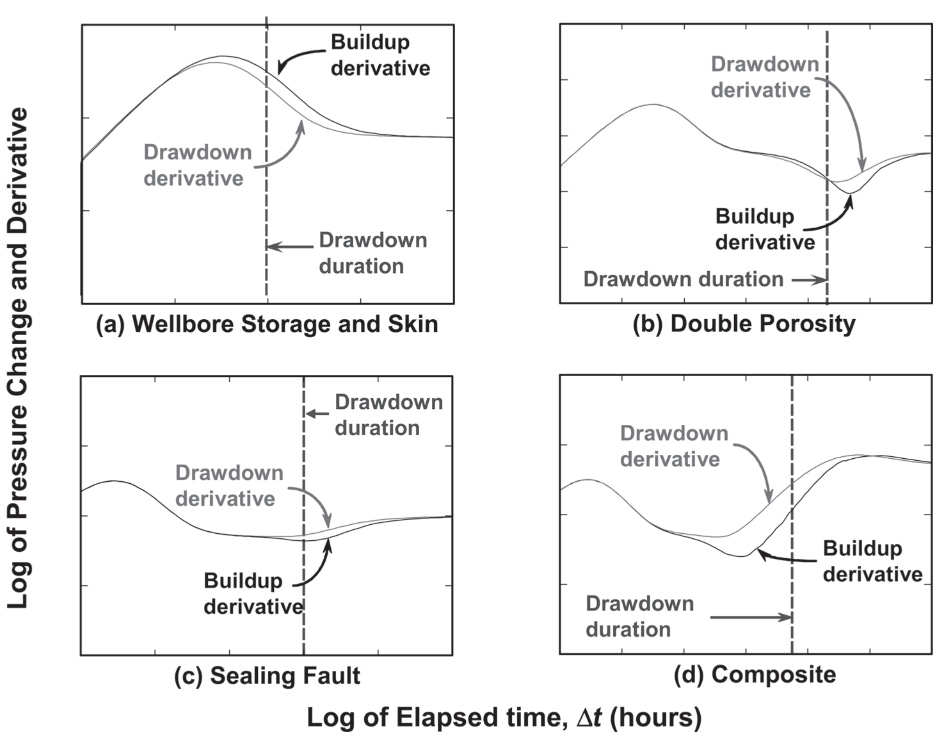

Fig. 12—Drawdown vs. buildup log-log derivative shapes.

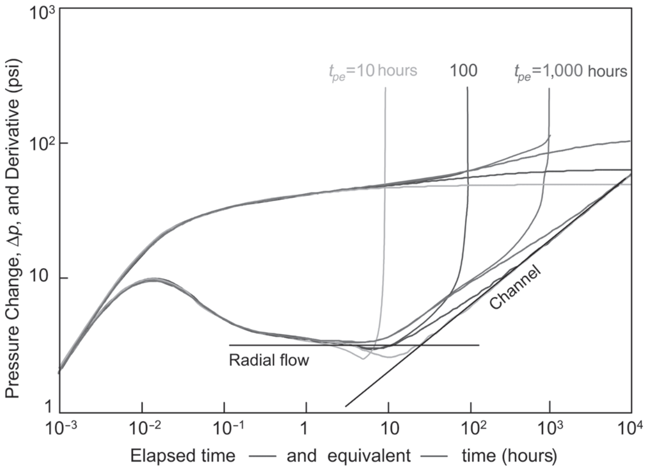

Fig. 13—Distortion of log-log derivative shapes because of equivalent time as a function of the production time (example of channel boundaries).

respectively. The slope must be obtained numerically, by use of an algorithm that must be able to remove as much of the noise as possible without altering the signal. This operation must be carried out with care because the shape of the resulting curve depends upon the method used to differentiate the data **(Fig. 14).**

A number of other factors can affect the shape of the derivative curve and therefore mislead the interpreter. Some can be easily identified: sampling frequency of the data acquisition, gauge resolution, time or pressure errors at the start of the period, erratic raw data points, or multiphase flow. Others are more difficult to see and may affect the analysis. These include end effects (if the last pressure in a flow period is too high or too low, the derivative shows an upward or downward trend, which must not be confused with a boundary effect), phase redistribution in the wellbore, and a pressure trend in the reservoir **(Fig. 15).**

But by far the most impact comes from the rate history. Inadequate description of the flow rate history is common in well test analysis. For instance, some flow-rate data may be missing, especially during drilling, stimulation, and the cleanup period. Fluid may have been injected into the well and not accounted for, or rates may be allocated and not measured. In addition, the rate history may have been truncated or simplified. Oversimplifying the flow-rate history can jeopardize the reliability of the pressure derivative as a diagnostic tool (this holds true also for the Horner and superposition graphs). For instance, truncating the production history by keeping only the latest rates before the period being analyzed yields erroneous buildup or multirate derivatives with upper trends above the correct stabilization line **(Fig. 16).** These could be mistaken for a decrease in mobility or storativity or a no-flow boundary. On the other hand, replacing all preceding flow periods with a single drawdown with a rate equal to the last rate before the period of interest and a duration equal to t_{pe} from Eq. 7 produces a hump on the log-log multirate derivative response (top of **Fig. 17).** This behavior could be mistaken for a composite behavior.

As a rule, the more recent the changes in production rates, the more detailed the rate history must be. Describing accurately the rate history during a period corresponding to the last 40% of the cumulative production of the well, and using Eq. 7 to calculate a t_{pe} for the first 60%, provides a correct derivative (Daungkaew et al. 2000) (bottom of Fig. 17).

Deconvolution

Deconvolution has received much attention recently (von Schroeter et al. 2001, 2004; Gringarten et al. 2003; Levitan 2005; Gringarten 2005; Ilk et al. 2005; Levitan et al. 2006), following the publication of a stable deconvolution algorithm (von Schroeter et al. 2001). As suggested by Fig. 1, it is not a new interpretation method, but a new tool to process pressure and rate data to obtain more pressure data to interpret. Deconvolution transforms variable-rate pressure data into a constant-rate initial drawdown with a duration equal to the total duration of the test and yields directly the corresponding pressure derivative, normalized to a unit rate. This derivative is therefore free from the distortions caused by the pressure-derivative calculation algorithm shown in Fig. 12 and from errors introduced by incomplete or truncated rate histories.

Some of the benefits of deconvolution are illustrated in **Figs. 18 through 20.** Fig. 18 shows pressure and rate data vs. time for a North Sea well. Downhole pressure is available only for the initial DST and a production test two years later. Surface rates are avail-

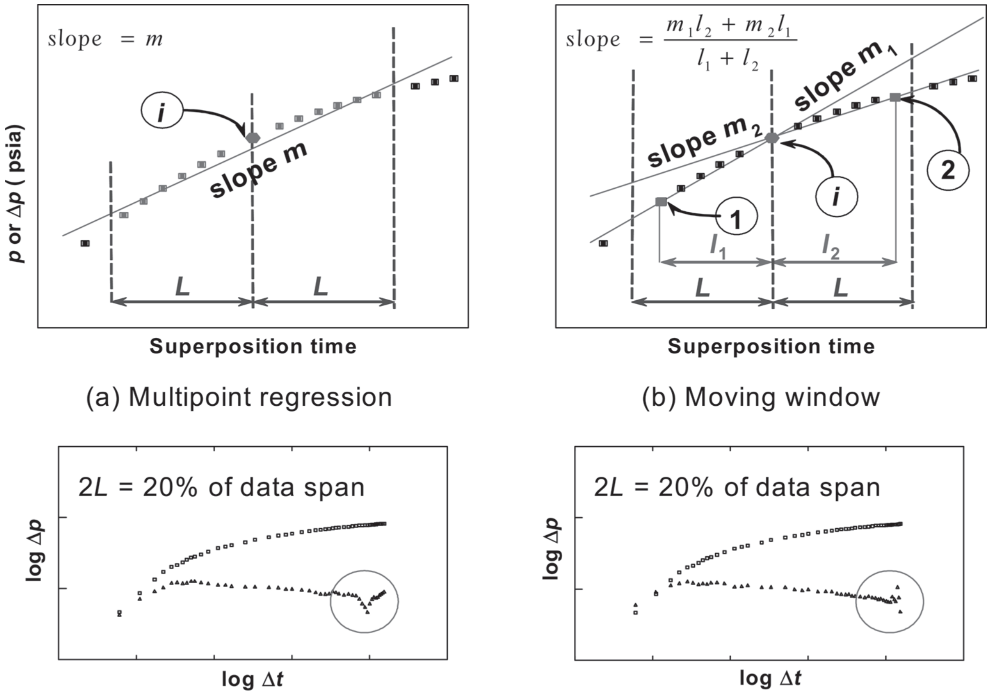

Fig. 14—Impact of differentiation algorithm (Bourdet et al. 1989) on log-log derivative shapes.

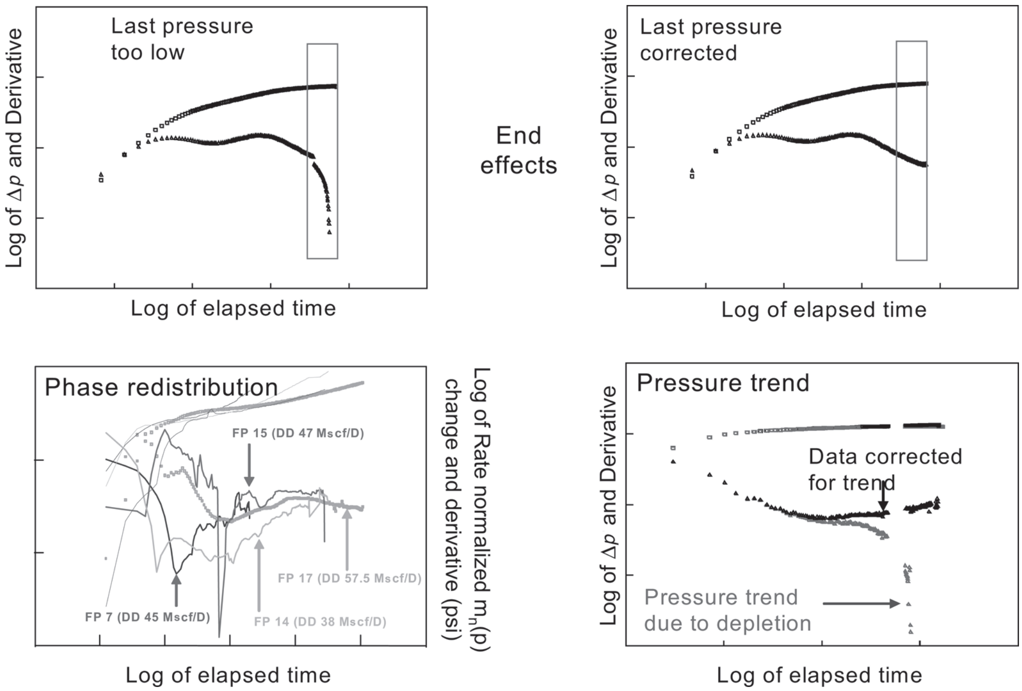

Fig. 15—Impact of end effects, phase redistribution in the wellbore, and pressure trend in the reservoir.

able for the entire period. The corresponding analysis plots are shown in Figs. 19 (log-log) and 20 (superposition).

Fig. 19 shows a rate-normalized log-log plot of the buildup derivatives for the two tests. Only 12 hours of data are available for conventional analysis. A radial-flow stabilization is apparent on the derivative data, but there is no evidence of boundaries. Yet the well has produced for approximately 12,000 hours, and the pressure has clearly declined, suggesting a closed reservoir. This is confirmed by the superposition plot of Fig. 20, which shows a downward shift in the buildup data.

There is therefore a knowledge gap between what is available to the interpreter and what has been seen by the well. This gap is closed by deconvolution of the last buildup: The deconvolved derivative shown in **Fig. 21** has a duration equal to the total du-

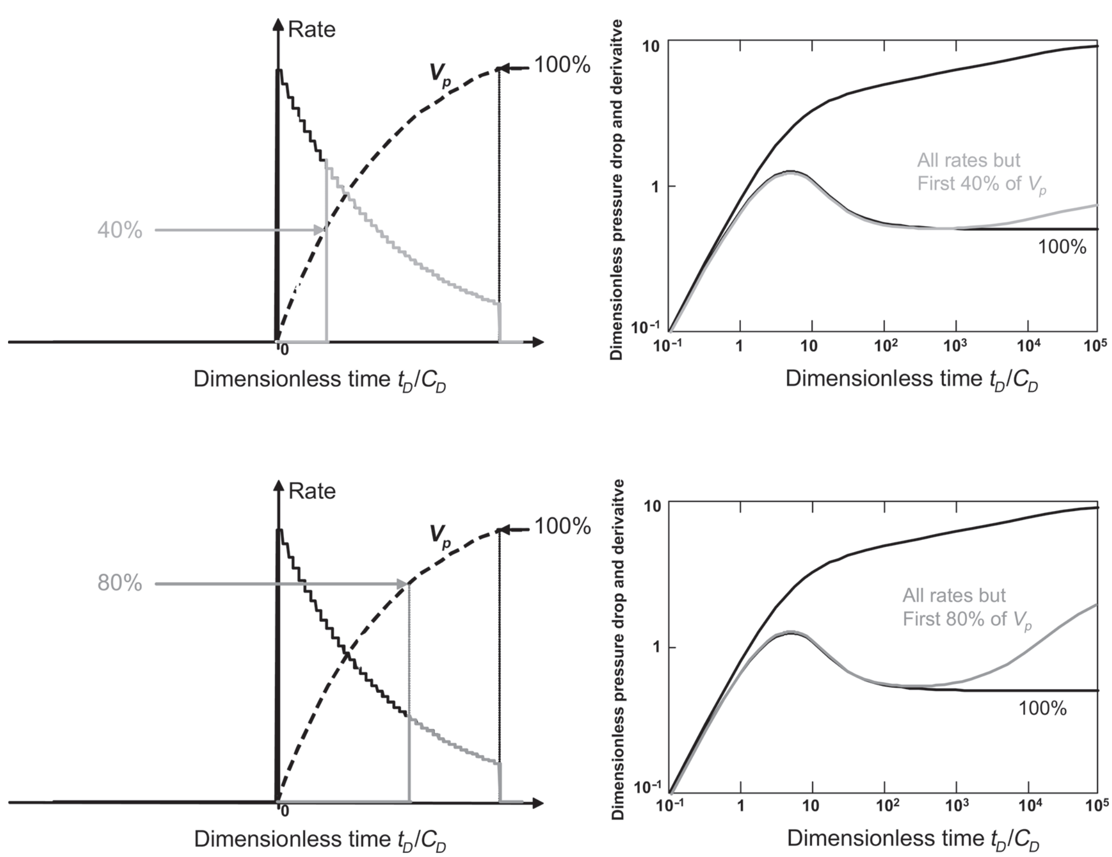

Fig. 16—Impact of truncating the rate history.

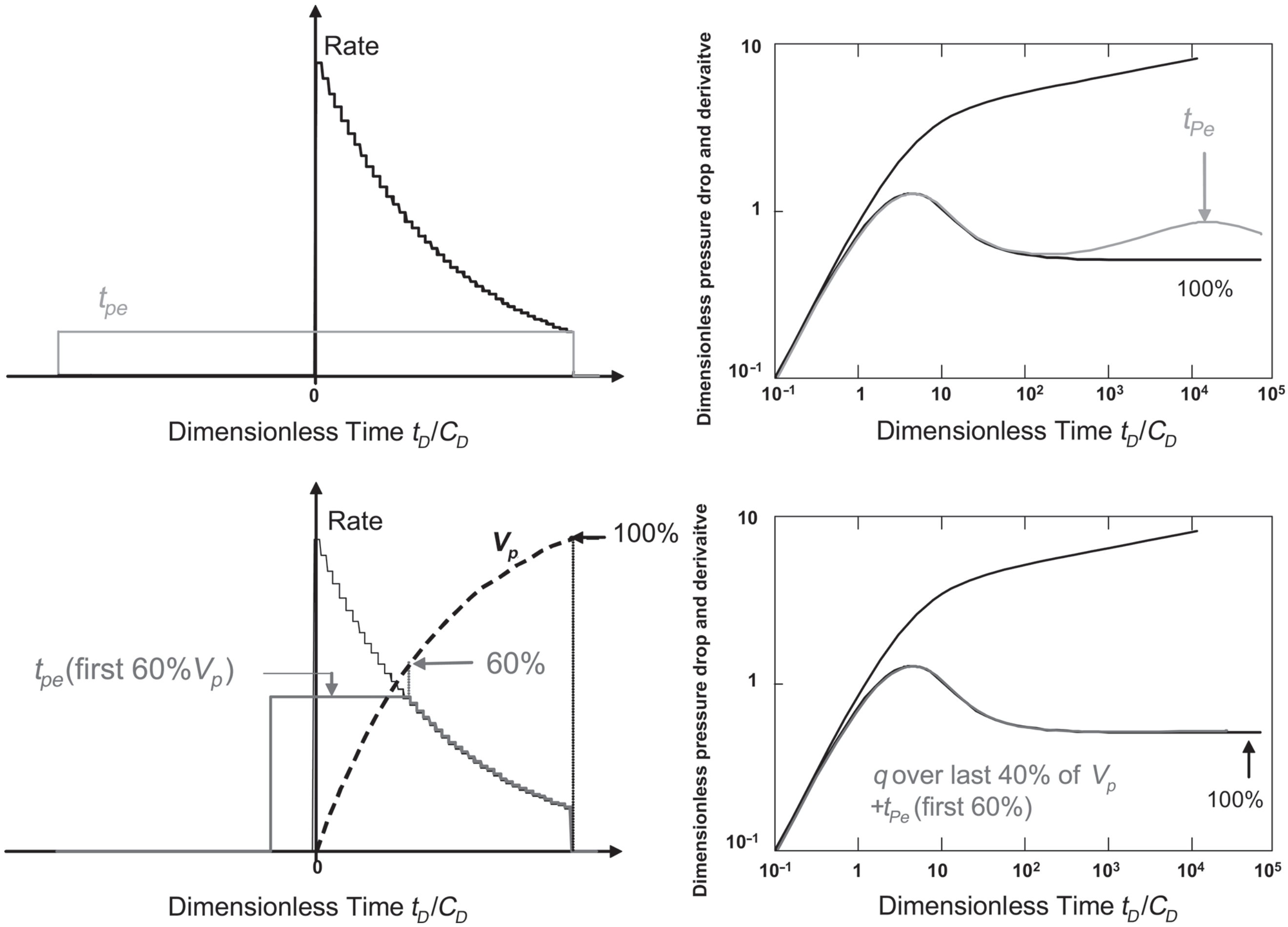

Fig. 17—Impact of approximating the rate history.

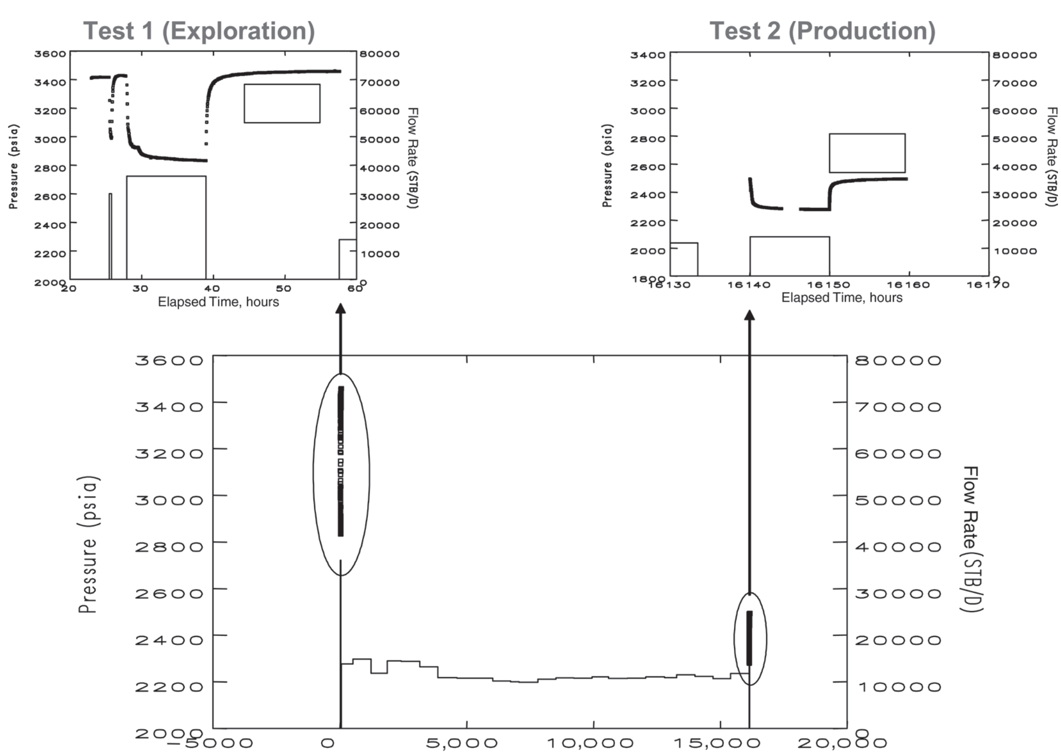

Fig. 18—Pressure and rate history, North Sea well.

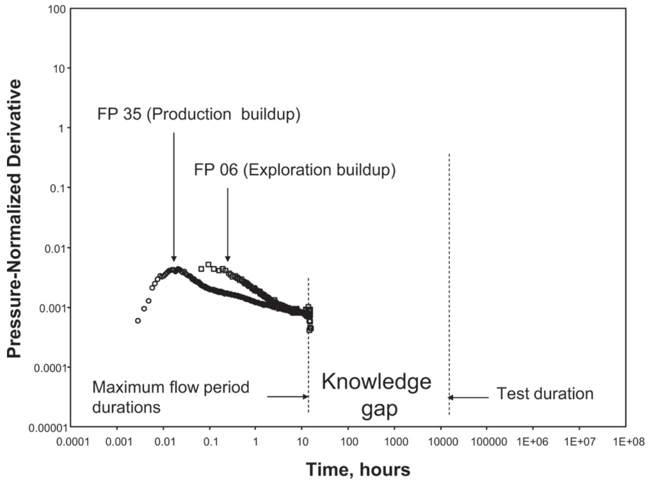

Fig. 19—Log-log derivative plot, North Sea well.

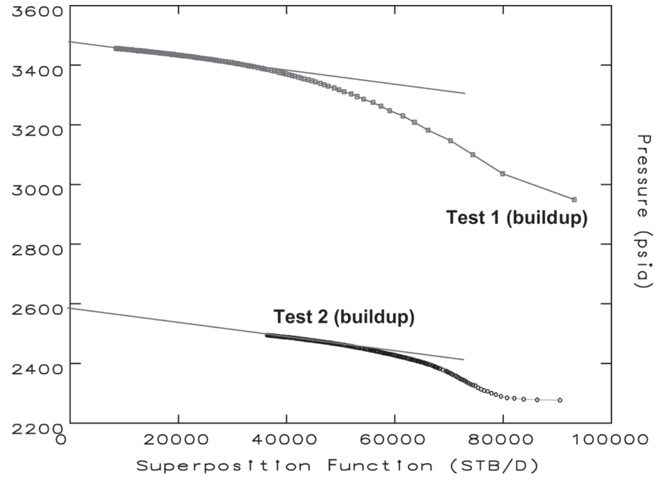

Fig. 20—Superposition plot showing depletion, North Sea well.

ration of the test and clearly shows no-flow boundaries, indicating a closed reservoir. The deconvolved derivative is actually defined during only two intervals, from zero hours to a time corresponding to the duration of the last buildup (12 hours) and from the start to the end of that buildup. It is interpolated in between.

Different implementations of the deconvolution algorithm have been documented in the literature (von Schroeter et al. 2001; Levitan 2005; Ilk et al. 2005), but all contain some control parameters, which must be adjusted by the user. Each control parameter value yields a different deconvolved derivative, and the interpreter must select the one which makes the most sense. For instance, the user must choose a level of regularization that imposes just enough smoothness to eliminate small-scale oscillations while preserving genuine reservoir features. This involves a degree of interpretation.

Other examples of the contribution of deconvolution to the identification of the interpretation model are shown in **Figs. 22 through 24.** Fig. 22 shows deconvolution applied to a 10½-month extended test, which included a series of drawdowns and buildups for 4½ months and a 6-month buildup [the test is described in Gringarten (2005)]. Because the flow periods in the initial 4½-month period were too short, the test could be interpreted only with the final buildup (i.e., after 10½ months of test data). Deconvolution, on the other hand, provides the complete behavior with only the first 5 weeks of data, a significant cost savings.

Fig. 23 shows a log-log plot of buildup data in a gas condensate reservoir slightly below the dewpoint pressure. The vertical axis is labeled in terms of normalized pseudopressure (Meunier et al. 1987), a modification of the single-phase pseudopressure function used to linearize the diffusivity equation in gas reservoirs (Al-Hussainy et al. 1965). The shape of the derivative suggests a composite behavior, pointing to the existence of a condensate bank. The deconvolved derivative, however, indicates a homogeneous behavior and channel boundaries, with the derivative shape caused by the derivative calculation algorithm as in Fig. 12. As a bonus, the radius of investigation is increased.

Fig. 24 also represents a gas condensate reservoir. In this case, it was believed that that there was no condensate bank. The deconvolved derivative clearly suggests the opposite.

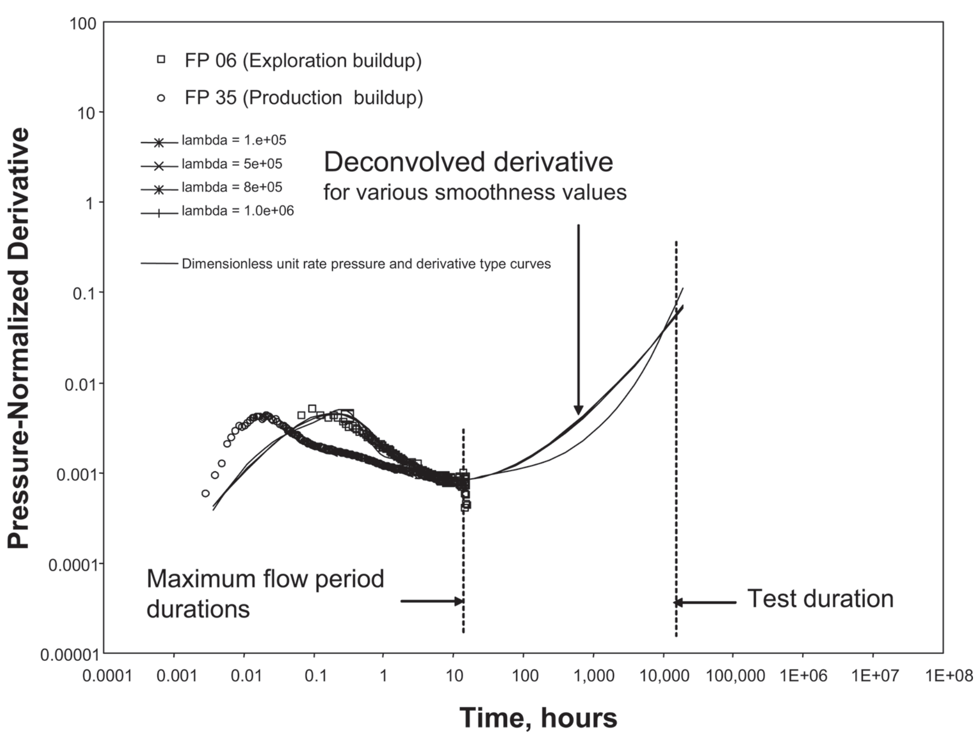

Fig. 21—Results of deconvolution, North Sea well.

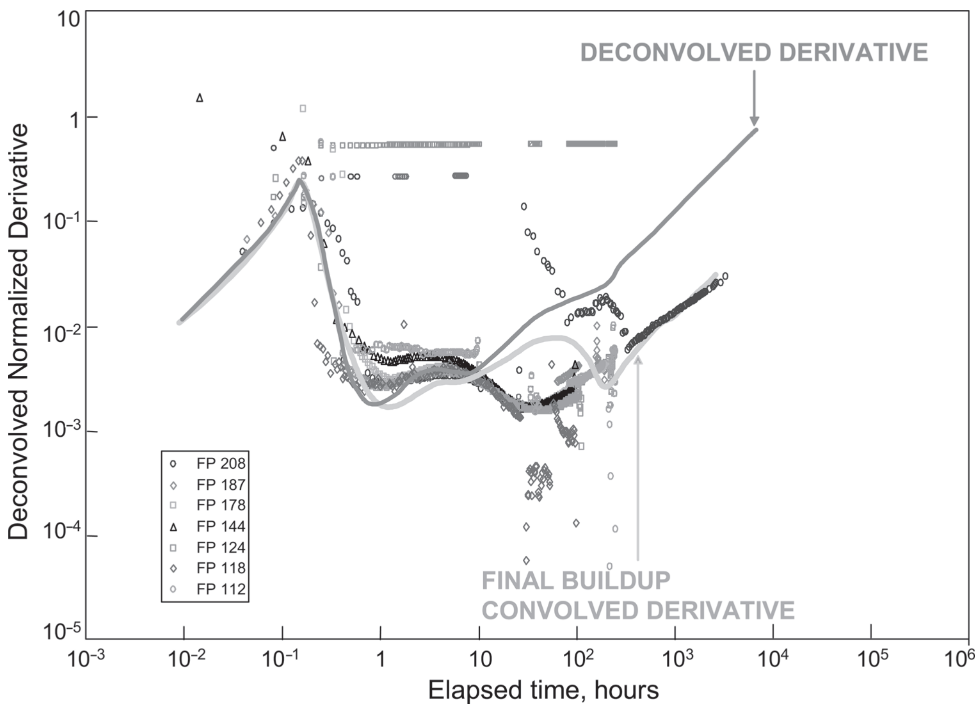

Fig. 22—Deconvolved derivative by use of all production data from extended well test and convolved derivative for last buildup.

Future Developments in Well Test Analysis

It has always been difficult to predict the next major developments in well test analysis, but it seems obvious that improvements essentially will come from three areas: richer signals (i.e., containing more information), better interpretation techniques, and more-complex models that represent the geology better. Efforts to reduce costs and environmental impact are also likely to impose additional changes.

Richer Signals. As already discussed, entire rate and pressure histories clearly provide different information from just a single buildup and some average rate representing the previous production. Another example of richer signal is the combination of pressure and individual layer rates required for multilayer analysis (Ehlig-Economides 1987). Not all richer signals will provide additional information, however. For instance, the use of a sinusoidal or periodic rate or pressure input signal in a well test (harmonic testing) instead of a step change does not because, for the same radius of investigation, harmonic tests are significantly longer than conventional tests (Hollaender et al. 2002a). As a result, they are limited mainly to short tests (high frequency) for the determination of skin effect and near-wellbore permeability (Fedele et al. 2004).

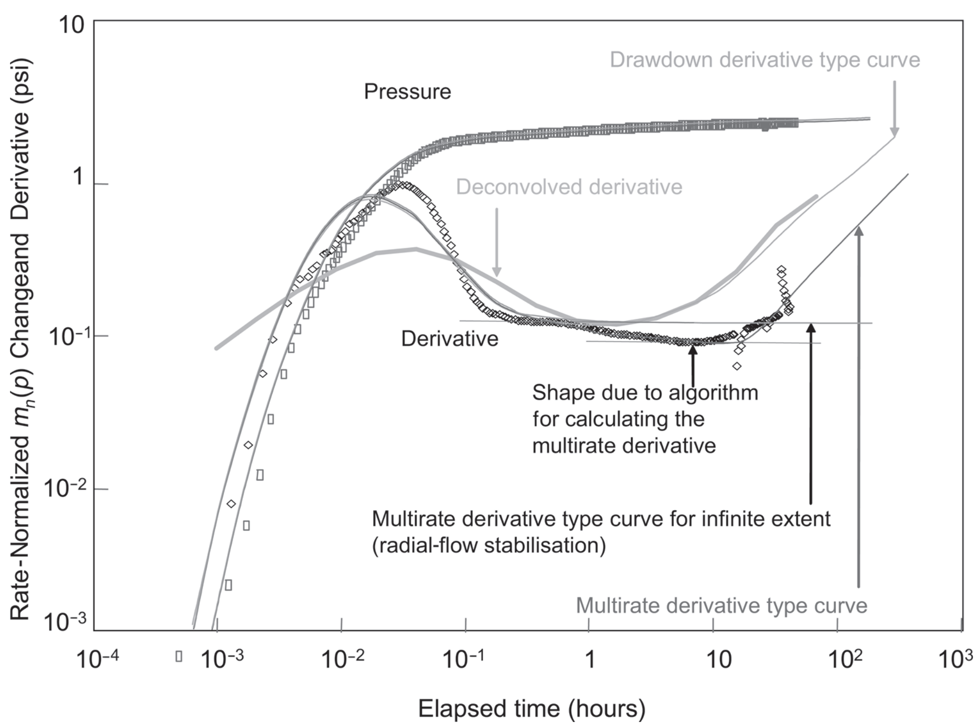

Fig. 23—Deconvolved derivative proving the distortion caused by the pressure derivative calculation algorithm.

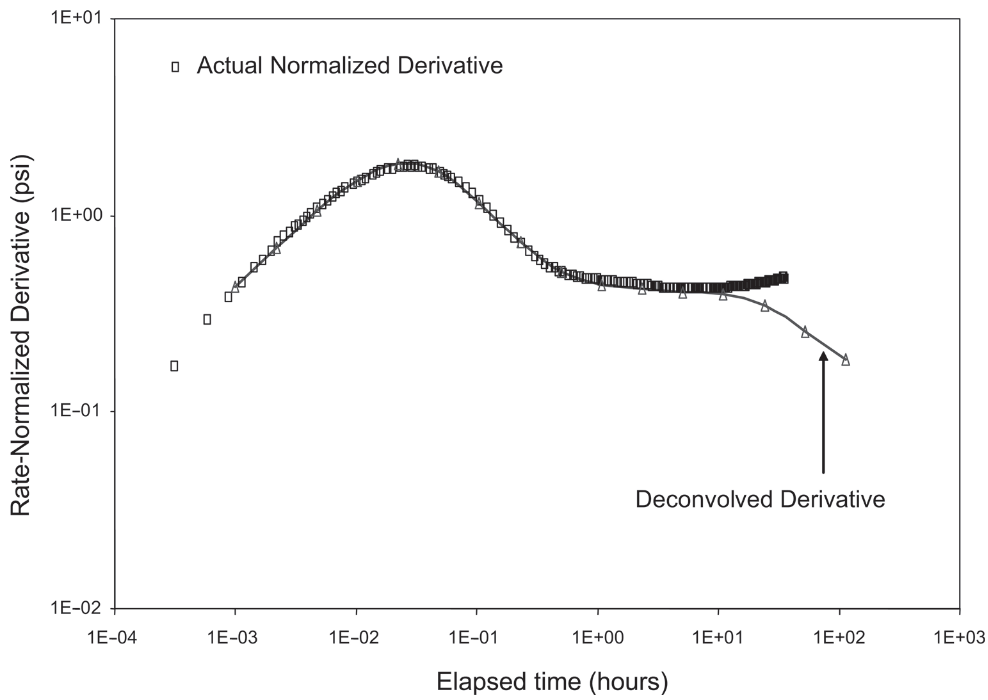

Fig. 24—Deconvolved derivative suggesting the existence of a condensate bank.

Better Interpretation Techniques With Uncertainty Ranges. It has already been mentioned in the discussion of Fig. 7 that any further improvement in interpretation technology can come only from significant improvements in the identification and validation steps. How to achieve this must be the subject of future research.

Another useful improvement will be the acknowledgment of uncertainties, which is long overdue (Gringarten 1986). Uncertainty in well test analysis results from errors in pressure, rate, and basic well and reservoir data; from the non-uniqueness of the interpretation model; and from the quality of the match with the interpretation model. Yet analysis results are usually reported as single values, often with unrealistic precision. Rules of thumb suggest that the permeability-thickness product and the wellbore storage coefficient are known within 15%; the skin effect within ±0.5; and distances within 25%, but no systematic study has been made of these uncertainties. Their cumulative effect can be represented as a probability distribution function (Gbo 1999; Azi et al. 2008), and this should be a mandatory feature in any well test interpretation software.

More-Complex Models. Reservoir geology is very complex, whereas well test interpretation models are rather simple. Some of the geological complexity can be seen and quantified from well test analysis with more-complex interpretation models that represent geological bodies more closely. For instance, vertical permeability distribution (Zheng et al. 1996) and meander information (Zambrano et al. 2000) in a fluvial meandering channel can be found from well test data in the transition between the radial flow and the channel flow regimes. The corresponding data are ignored when the analysis is performed with the usual simple interpretation models.

The Use of Numerical Simulation Tools. Claims of better analyses by use of high-resolution numerical models have been a recurrent feature in the well test analysis literature. The usefulness of numerical simulators for well test analysis is mainly in the solution of the direct problem (i.e., calculating the behaviors of well-defined interpretation models and verifying analysis results). Numerical simulation, however, can help with the inverse problem (identifying the interpretation model), by modeling the effects of potential geological features, such as discontinuous boundaries of various shapes or layering, and the impact of suspected phase changes as in gas condensate reservoirs below the dewpoint pressure or volatile oil reservoirs below the bubblepoint pressure. These forward simulations are mandatory in complex geological or completion situations, to distinguish between potential causes of an observed behavior (Gringarten et al. 2006).

Another important use of high-resolution numerical well test simulators is as part of the reservoir characterization process. The purpose of reservoir characterization is to define a reservoir model that honors both static and dynamic knowledge about the reservoir. Once the reservoir model is constructed, one must verify that this reservoir model is consistent with all available information and interpretation models. This means that the reservoir model must reproduce all the data that were used in the characterization process (i.e., seismic, logs, production data if available, and well tests) (Gringarten 1998).

Cost and Environmental Constraints. Well testing in exploration and appraisal wells has become increasingly unpopular in recent years. Reasons include costs, safety, and environmental impact (Hollaender et al. 2002b). Well testing also has become rare in production wells because of the potential revenue loss during buildups. Whether suitable alternatives can be found is the subject of regular debate. Alternatives to DSTs include wireline formation tests and mini-DSTs for sampling, permeability, and initial reservoir pressure; core and log analyses for permeability; and geology, seismic, and geochemistry for reservoir heterogeneities, boundaries, and fluid contacts. However, there is no suitable well-testing replacement for finding skin (well damage), effective permeability and hydraulic connectivity throughout large reservoir volumes, and obtaining the large fluid samples required for sizing surface processing facilities, or for determining the quality of the fluids from a commercial viewpoint. Production tests, on the other hand, tend to be replaced by continuous recording with permanent pressure and rate gauges in production wells. These data are particularly well suited for analysis with deconvolution.

Deconvolution actually blurs the difference between conventional well test and production-data analysis (Ilk et al. 2006). During the course of many years, several methods have been proposed to analyze production data to extract all the information that is usually obtained from conventional well test analysis without the constraint of shutting in wells. These methods have been attempting to convert variable rate/pressure into variable pressure at constant rate or into variable rate at constant pressure. Examples are the decline curve analysis by use of material balance time (Doublet et al. 1994), the reciprocal productivity index method (Crafton 1997) and the rate-time type-curve analysis (Chen and Teufel 2000). The aim of all these methods is achieved with deconvolution, which produces much cleaner transformed data and much better results when estimating permeability and distances to boundaries.

Conclusions

Well test analysis has come a long way since the 1950s when the interpretation methods on the basis of straight lines gave unreliable results. We now have a methodology that provides repeatability and techniques with derivatives and deconvolution that enable a high level of confidence in interpretation results.

It can be safely predicted that the importance of well test analysis in reservoir characterization will continue to increase as new tools such as permanent downhole pressure gauges and downhole flowmeters become more widely used and as the scale relationship with the interpretation of other data from geophysics, geology, and petrophysics becomes better understood.

Nomenclature

c_t = total compressibitiy
$f(\Delta t)$ = function representing a particular flow regime
h = reservoir thickness
I = input signal
k = reservoir permeability
O = output signal
O' = output signal from model
p_i = initial pressure
$p_w\,(\Delta t)$ = pressure at an elapsed time Δt
q = flow rate
q_i = constant flow rate during flow period i
S = system
t_{eff} = Agarwal effective time
t_p = drawdown duration in a drawdown/buildup test
t_{pe} = equivalent Horner production time
V_p = cumulative production
Δp = pressure drop
Δt = elapsed time from last rate change
Δt_i = duration of flow period i
μ = fluid viscosity
Σ = interpretation model
φ = reservoir porosity

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