Transient Well Testing

Transient Well Testing

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Foreword

In petroleum engineering, description and characterization of the reservoir/well system is paramount to the tasks of managing, appraising, producing, and recovering as much fluid as possible from different fields. None of the core technologies used to obtain information about the reservoir/well system is more valuable than transient well testing, the subject of this monograph. Development in transient well testing began more than 70 years ago in ground water hydrology and petroleum engineering and will no doubt continue for decades to come. In the first SPE monograph published in 1967, C.S. Matthew and D.G. Russell covered *Pressure Buildup and Flow Tests in Wells.* About 10 years later, SPE Monograph No. 5, *Advances in Well Test Analysis,* by R.C. Earlougher, Jr. was published. Now, the third SPE monograph covering this area of technology is produced. Significant developments in transient well testing are occurring at a brisk pace, and its wide use in all phases of the life of oil and gas fields resulted in devoting several publications to this topic.

Developments in transient well testing tracked changes in other aspects of petroleum engineering as well as other technologies. Such developments are reflected in the differences among the three transient well testing monographs. Early days (1930s–1940s) saw heavy dependence on analytical solutions as shown in Monograph No. 1. With the advent of numerical solutions in reservoir engineering (reservoir simulation) in the 1960s, use of numerical solutions in analyzing transient tests began to increase by the time Monograph No. 5 was published. Advances in personal computers expanded our abilities to rigorously match transient testing data, simulate complex reservoir/well systems, and led to the current analysis methods described in this monograph. Advances in testing tools changed the types and frequency of testing wells. Good examples of new tools are wireline formation testers and permanent downhole gauges.

As a result of the new developments, all segments of the industry are now involved in transient testing. Integrated oil and gas companies, oil field service companies, software development companies, consulting firms, and academic institutions are participants in the development of tools, solutions, and methods of transient testing. The list of authors of the different chapters of this monograph and their affiliations is an indicator of the inclusive nature of the current transient testing technology. Authors of various chapters were selected for their known expertise and publications in the topics of their chapters. A natural result of using multiple authors is that sometimes differences of opinion exist among them, and although SPE monographs reflect generally accepted engineering practices, complete agreement on all points is not possible. Therefore, the information included in each chapter is presented by the chapter's author and does not necessarily reflect the opinions of all other authors.

Continuous developments in petroleum engineering will lead to new challenges in transient testing. Advances in drilling and well construction, completions and smart wells, wells' instrumentation, and testing tools will require new or changed testing methods. Reservoirs of increased complexity, that are currently difficult to test, will be increasingly accessed, and testing techniques should be modified to characterize them. Developments in computing technology and data gathering systems will change and most probably enhance the capabilities of transient testing. Integration of different methods of reservoir characterization will mature and provide both a help and a challenge to transient well testing. Normal transient testing methods as presented in this monograph will change and improve as a result of the above-mentioned developments. Additional publications describing new methods to design, conduct and analyze tests will make their way to the literature. Lastly, the fourth SPE monograph on transient well testing will be written.

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Dedication

This monograph is dedicated in memory of Henry J. Ramey Jr. and William E. Brigham, pioneers in transient well testing whose insights, research, field applications, and commitment to education continue to inspire many of the current subject matter experts.

Contents

Chapter 1

Introduction

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1.1 Value of Well Testing

A reservoir is in a transient state when the pressures or saturations of fluids are changing with time and the rate of change is different at different locations. Monitoring flow rate and pressure while the reservoir is in a transient state yields valuable information about the properties of the reservoir system. For the purpose of this monograph, a reservoir system is defined as the combination of the reservoir and a well or a group of wells. For example, measuring the flow rate and pressure drawdown in a producing well while the reservoir is in steady state provides information about the reservoir permeability or the wellbore skin, but not both. Measuring the same two parameters as a function of time while the reservoir is in a transient state provides information about both permeability and skin. As will be shown in this monograph, numerous other properties of the reservoir system may be obtained from different types of transient tests. The value of transient well testing, or simply well testing, lies in its ability to provide the petroleum engineer with properties of the reservoir system so that predictions of future performance can be made. From the early days, when well tests provided the value of the average reservoir pressure needed by the reservoir engineer for material balance calculations and the skin needed by the production engineer to design well workovers, to recent times, when well tests provide dynamic constraints for reservoir descriptions generated from static information and determine the length and conductivity of hydraulic fractures, transient testing has been a valuable and continuously advancing area of petroleum engineering.

Well testing has the same value as well to groundwater hydrologists, who, practically speaking, solve the same problems as the petroleum engineer. As a matter of fact, well testing originated in groundwater hydrology (Theis 1935).

Designing, conducting, and analyzing well tests cost time and money. Most of the cost is associated with conducting the test, especially the cost of rig time in testing exploration wells and the cost of production curtailment when testing wells in developed reservoirs. It is important to balance the cost of well tests against the value of the information obtained from the tests.

Well testing, as will be explained in Chapter 2, provides indirect determination of the reservoir parameters. As with all other indirect reservoir description methods (for example, history matching of reservoir performance), the results will not be unique. Therefore, data from well tests should not be interpreted in the absence of knowledge of reservoir geology and wellbore conditions. Matthews and Russell (1967) cautioned that "pressure analysis techniques must be used objectively and in conjunction with all available reservoir information," and stressed that "our goal is optimization of recovery through characterization of the reservoir system." Earlougher (1977) stated, "It would be a mistake to either oversell or undersell pressure transient testing and analysis. It is one of the most important in a spectrum of diagnostic tools."

1.2 Need for This Monograph

Matthews and Russell (1967) wrote in the first-ever SPE monograph, "We hope that from the objective treatment of pressure analysis methods which we have endeavored to give in this monograph, the usage of the methods will be stimulated. Also, we hope that in some measure the development of more rigorous methods will result." Their hope was realized over the following three decades as activities in the area of well testing intensified, numerous papers describing research in oil companies and American universities were published, rigorous methods to analyze data were developed, and the ability to characterize reservoir systems using well tests increased. The main tool described for analyzing well tests in the Matthews and Russell monograph, the semilog plot, is used today as one of several specialized plots and is no longer the main tool for analysis.

Earlougher (1977), in the second SPE monograph on well testing, noted that there had been significant expansion of knowledge about well testing since the publication of Matthews and Russell's monograph and added, "I expect that there will be updated well test analysis monographs at regular intervals for many years to come." Development activities continued to change the technology behind well testing. Oilfield service companies and universities outside the United States joined in research activities. The advent of desktop computers enabled the petroleum engineer to apply new and more-rigorous treatments to well-test data. Well-testing-specific software packages incorporating the latest technical advances were developed. The main method of analysis described in Earlougher's monograph, type-curve matching, can be found in only a small number of current software packages and is used only in special cases.

Several books have been published on the subject of well testing since Earlougher's monograph (Lee 1981; Streltsova 1988; Raghavan 1993; Sabet 1991; Horne 1995; Lee and Wattenbarger 1996; Hasan and Kabir 2002). Each book addressed a special segment of well testing. Lee authored a textbook for undergraduate students on well testing in 1981. Streltsova (1988) and Raghavan (1993) described mathematical treatments of several well-testing problems, while Sabet (1991) presented a practical description of analytical methods, and Horne (1995) covered computer-assisted well-testing interpretation. Lee and Wattenbarger (1996) devoted a significant part of their book on gas reservoir engineering to pressure-transient testing. Hasan and Kabir (2002) authored a book on fluid flow and heat transfer in wellbores. Lee authored another textbook on pressure-transient analysis with Rollins and Spivey (2003).

A gap in the petroleum engineer's library for a comprehensive book covering the state of the art in well-test analysis has existed for some time now. Practicing petroleum engineers need a single up-to-date reference for transient testing of oil, gas, and water wells. This monograph has been written to fill this gap.

1.3 Scope of This Monograph

Like its predecessors, SPE Monographs 1 and 5, this monograph is intended to be a standalone publication. Monographs, by definition, contain accepted engineering practices for obtaining results in various situations. It is preferable to include background information about the theory behind these engineering practices. Complete theoretical development and equation derivations are included only where essential to cover the subject adequately. In all cases, sufficient reference materials are cited to allow the reader to obtain more detailed information or to conduct further research. Otherwise, it would have been impossible to produce a monograph that covers all areas of transient well testing in a reasonable volume. This is true because of the wealth of work that has been done in this area of petroleum engineering technology. Whereas Monographs 1 and 5 were completely written by one or two authors, this monograph is the collective work of several authors, each contributing between one and three chapters. There are two reasons for this approach. First, with the decreased number of engineers working in the industry today with respect to production volumes, it is increasingly difficult for a few volunteer authors to complete a monograph in a reasonable time. Second, it was believed that asking multiple authors to write a chapter each in areas of expertise where they have published repeatedly in refereed journals would result in a better product. With this multiple-author approach, the reader should recognize that the information presented in each chapter reflects the experience and opinions of the authors of that chapter and may not necessarily represent the opinions or recommendations of other authors of this monograph.

The monograph begins with an explanation of the basic concepts of well testing in **Chapter 2.** An explanation of the reservoir description problem and the basic equations that govern well testing sets the stage for describing the general procedure used today to design and analyze well tests as well as the different types of well tests and the information obtained from each type. The different kinds of measurements taken during well testing are described in **Chapter 3.** These measurements include pressure, flow rates, temperature, and others. The gauges used to obtain these measurements are discussed, together with their specifications and limitations. Wireline formation testers, downhole shut-in devices, and permanent downhole gauges also are included. In **Chapter 4,** the concept of the value of information is introduced. This chapter guides the reader through a procedure to decide objectively whether running a given test is justifiable based on its cost and the information to be gained from the test. With a background in the basic concepts of well testing, the measuring tools used, and the value of the information obtained from the tests, the reader is now ready to begin to investigate what is involved in testing a simple uniform reservoir. This topic is covered in **Chapter 5.** This chapter introduces the reader to the basic tools used in the analysis, such as the diagnostic plots, specialized plots, and the pressure-derivative technique. **Chapter 6** discusses the effects of the wellbore on well testing, including the effects of wellbore fluids, completion, and skin. In **Chapter 7,** the outer boundary effects are described, and the reader is shown how to recognize outer boundaries and calculate their distances from the well. The use of computers to assist the engineer in designing and analyzing well tests is the subject of **Chapter 8.** This chapter also introduces the reader to the important concepts of regression analysis and confidence intervals and how to use them in well testing. It briefly introduces the subject of numerical well testing, which is described in more detail in Chapter 23 and probably will dominate the next SPE monograph on well testing. **Chapter 9** discusses the software used in well testing. It suggests to the readers the basic components that should be included in the software they use, together with some aspects of the analysis that can be done only by using computer software. Naturally fractured reservoirs are discussed in **Chapter 10.** The reader is shown how to recognize when the reservoir is behaving as a double-porosity medium (another name for a naturally fractured reservoir) and how to calculate the properties of this system. Hydraulically fractured wells are the subject of **Chapter 11.** The various models for characterizing fractured wells are presented, and the proper analysis techniques are described. The use of the resulting information in micro- and minifracturing operations is illustrated, and the reader is shown how to use the information to optimize analysis of fractured wells and improve fracturing operations. **Chapter 12** covers the tests that are run to assess the deliverability and storativity of reservoirs. Although these tests generally are associated with gas reservoirs, the reader will discover in this chapter that they are valid for oil reservoirs as well.

Chapter 13 considers the subject of slanted and partially penetrating wells, and **Chapter 14** addresses horizontal wells. These two chapters show the different flow regimes that can be expected when testing these wells, the calculation of reservoir properties, and the fracturing of horizontal wells. Testing under multiphase conditions is the subject of **Chapter 15.** After a brief theoretical background, the testing of reservoirs under various multiphase conditions is discussed. This includes oil reservoirs with solution gas, gas-condensate reservoirs, and coalbed-methane systems. The subject of simultaneous transient flow rate and pressure testing is discussed in **Chapter 16.** The principles of convolution and deconvolution are introduced, the advantages of combined rate and pressure testing are listed, and the analysis techniques to perform these tests are described. **Chapter 17** introduces the reader to the subject of permanent downhole gauges and the various techniques that may be used to handle a large number of data points and reduce them to an appropriate number for analyzing transient tests. The chapter also discusses production data analysis and shows its strong link to pressure-transient analysis. Recent developments in deconvolution are also described in this chapter. **Chapter 18** covers multilayer testing. It begins by describing the various types of multilayer tests together with the procedures, advantages, and limitations of each type. The analysis methods themselves are then introduced. Multiple-well tests are considered in **Chapter 19.** There the different types of horizontal and vertical multiple-well tests are described. Design and analytical techniques for each type of test are explained. Testing of injection wells is described in **Chapter 20.** Step rate, injection, and falloff tests are explained. Effects of multiphase flow, usually encountered when injection is restarted in a well, as well as thermal effects due to differences between the reservoir and injected-fluid temperatures, are addressed in this chapter. **Chapter 21** covers one of the two main methods of exploration well testing, wireline formation testing, and **Chapter 22** addresses the other method, drillstem tests. For both of these methods, the tools used and the results that may be expected are described. Finally, **Chapter 23** tackles the subject of integrating well testing with other reservoir description methods. It discusses static and dynamic data, how these other methods influence well test analysis and vice versa, available technology, and future directions.

In all chapters, wherever appropriate, illustrative examples are included. Field examples also are included throughout the monograph to demonstrate the application of various methods of analysis. At the end of each chapter, practical considerations for the theory and methods contained in the chapter are discussed.

1.4 How To Use This Monograph

This monograph is written to be used as a "go-to" handbook by practicing petroleum engineers. Although the chapters of the monograph are organized in a logical order to present a comprehensive treatment of the subject of transient well testing as it may be offered in a university or training course, it is recognized that a practicing engineer may not use the monograph in this manner. In this case, the reader is encouraged to review Chapters 1, 2, 5, 6, and 7 to become familiar with the state of the art in well testing and how to design and analyze well tests. In addition, the reader should review the table of contents to find out the topics covered in the monograph. Then, as the need arises for testing a given type of reservoir system such as a horizontal well or a double-porosity reservoir, or for conducting a specific test like a pulse test, the reader may refer to the specific chapter containing the needed information.

1.5 Nomenclature and Units

Consistent nomenclature is used throughout the monograph and can be found in the Nomenclature section at the end of the monograph. In some cases, however, the chapter authors found it necessary to use different symbols in some parts of their chapters, in which case they have described these different symbols below the equations where they occurred or at the end of the chapter. In these situations, the nomenclature used in each section supersedes that given at the end of the monograph. Equations that appear in appendices are referenced back to the pertinent chapters and vice versa. The standard symbols adopted by SPE are used as much as possible. Conventional oilfield units are used in this monograph; a list of these units is presented in Appendix A, along with conversion factors between oilfield and metric units. A table of conversion factors useful in well testing, first introduced by Earlougher (1977), also is reproduced in Appendix A for the sake of completeness and convenience.

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Chapter 2

Basic Concepts of Transient Testing

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2.1 Describing Underground Reservoirs

The aspect of petroleum engineering that distinguishes it from other engineering disciplines is that petroleum engineers do not design the systems they work with. Unlike an engine designed by a mechanical engineer or a structure designed by a civil engineer, the oil and gas reservoirs are given to the petroleum engineer. In this regard, petroleum and mining engineering are similar. In the case of mining engineering, however, the system is usually physically accessible to the engineer, and direct measurement of the properties of the system is possible. In petroleum engineering, the system is not physically accessible, and engineers have to rely on indirect measurements to determine the properties of the system. This is the similarity between petroleum engineering and groundwater hydrology. A special case of indirect determination of reservoir properties is that of measuring the flow rate and pressure drawdown of a well producing under stable conditions and using this information to calculate the reservoir permeability. Transient testing is the general case that encompasses measurement of flow rates and pressures under various conditions. Assume that a well is producing oil at a constant rate of q STB/D for a period of t_p hours. The well is then shut in. As shown in **Fig. 2.1,** the bottomhole pressure of the well will decrease (draw down) as production begins and will increase (build up) when the well is shut in. How the pressure changes is a function of the properties of the reservoir system. Disturbing the reservoir by changing the flow rate of a well and observing the resulting pressure change is a noisy experiment that may be run to determine the dynamic reservoir properties indirectly. Changing the rate and measuring the pressure in the same wellbore is a single-well test. Fig. 2.1 also shows the change in pressure at an offset well because of the rate change. The change in pressure in the offset well is smaller than in the active well, and there is a time lag between the beginning of the change in flow rate and the corresponding change in pressure at the offset well. Changing the flow rate in a well and measuring the pressure response in another well is a multiple-well test. Although most of the time well testing involves changing the flow rate and measuring the pressure response, transient testing also involves measuring the change in flow rate due to pressure changes or the change in flow rates of individual layers as a result of a change in the total flow rate of the well.

2.2 Flow Through Porous Media

To understand pressure-transient analysis, three terms must be defined: steady-state flow, pseudosteady-state flow, and unsteady-state or transient flow. Steady-state flow exists where there is no change in density at any position within the reservoir as a function of time. Practically, this means that there is no change in pressure at any position as a function of time or as production changes. Obviously, this situation rarely exists within the reservoir. However, the concept of steady state is a very practical one. An example of steady-state flow is pattern flooding, in which the injection and producing wells are operated at constant rate or pressure for a long time. Pseudosteady-state flow exists when the pressure change over time is the same everywhere in the reservoir. In other words, although the reservoir pressure is changing, there is no relative change in pressure at various points in the reservoir—hence the term pseudosteady-state. A good example of pseudosteady state is a reservoir under depletion. Unsteady-state or transient flow occurs when the pressure change with time is

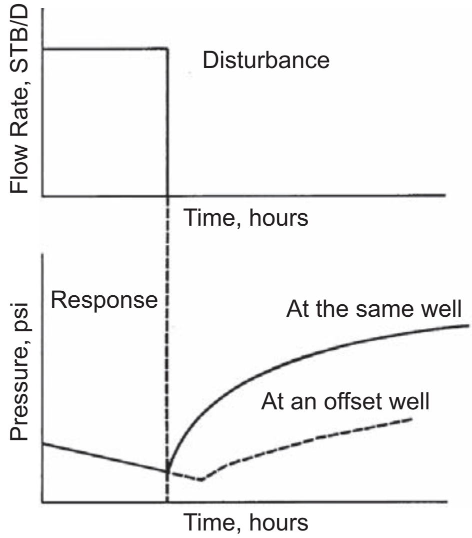

Fig. 2.1—Schematic of flow rate and pressure changes.

different at different locations. This happens, for example, when a well is put on production or injection or when an active well is shutin for a buildup or falloff test.

To develop the equations that describe the fluid flow in the reservoir, the laws of continuity must be combined with transport-rate equations and statements of equilibrium. The laws of continuity for most reservoir engineering applications are:

1. Conservation of mass
2. Conservation of energy
3. Conservation of momentum

The principle of conservation of mass is satisfied by the material balance equation. The transport-rate equation used is Darcy's law, and the statement of equilibrium is represented by equations of state. Matthews and Russell (1967) presented the derivation of the diffusivity equation that describes flow in the reservoir by combining the above equations, and Earlougher (1977) discussed their practical use. Both Matthews and Russell and Earlougher have shown that the pressure at any point in a homogeneous, isotropic reservoir due to the horizontal flow of a slightly compressible fluid toward a central well producing at a constant rate is given by Eq. 2.1. A homogeneous reservoir is a reservoir in which the properties, such as porosity, permeability, and thickness, are the same at any location in the reservoir. An isotropic reservoir is a reservoir the properties of which at any location are the same in all directions. For example, the permeability in the east-west direction is the same as the permeability in the north-south direction.

$$p(r,t) = p_i - \frac{q\mu}{2\pi kh}\left[-\frac{1}{2}E_i\left(-\frac{\phi\mu c r^2}{4kt}\right)\right] \quad \text{(2.1)}$$

The exponential integral is defined by

$$\mathrm{Ei}(-x) = -\int_x^\infty \frac{e^{-u}}{u}\mathrm{d}u \quad \text{(2.2)}$$

Values may be taken from tables (Abramowitz and Stegun 1964) or approximated using

$$\mathrm{Ei}(-x) \cong \ln(x) + 0.5772 \text{ for } x < 0.0025 \quad \text{(2.3)}$$

2.3 Dimensionless Variables

The concept of dimensionless variables is useful in solving transient testing problems and is illustrated here using an example. Assume there are three wells in a large oil sand. Well A produces at a rate of 6,000 STB/D, causing pressure drops at Wells B and C. Well B is 1,000 ft from Well A, and Well C is 3,162 ft from Well A. With the data given below, one can calculate the pressure drop at Wells B and C using Eq. 2.1.

Oil formation volume factor	1.3	RB/STB
Oil viscosity	0.5	cp
Total compressibility	10^{-5}	psi^{-1}
Thickness	600	ft
Porosity	0.15	fraction

Table 2.1 shows that the pressure drop at Well B after 24 hours (2.10 psi) is the same as the pressure drop observed at Well C after 240 hours, and that the pressure drop at well B after 48 hours (2.72 psi) is the same as that at Well C after 480 hours. Examination of the argument of the exponential integral in Eq. 2.1 makes the reason clear. r^2/t in this argument has the same value at Well B ($r^2 = 10^6$ ft^2) after any time t as at Well C ($r^2 = 10^7$ ft^2) after a time of $10t$. Therefore, if the pressure is calculated as a function of r^2/t instead of t, the results will be valid for any location in the reservoir. One can generalize this discussion by considering the pressure change in two reservoirs with identical properties except that the porosity of one is ϕ_1 and the other is ϕ_2. In this case, if the pressure is calculated as a function of $\phi \bullet r^2/t$, the results will be valid for any location in either reservoir. The next step is to generalize the discussion further by assuming that the permeability of the first reservoir is k_1 and the second reservoir is k_2. In this case, one must note that the permeability appears in the argument of the exponential integral as well as the term multiplied by the pressure drop, and the generalized function will therefore calculate Δpk as a function of $\phi r^2/kt$. Finally, if all properties of both reservoirs were allowed to be different, the term $[(\Delta pkh)/(qB\mu)]$ as a function of the term $[(\phi\mu c_t r^2)/(kt)]$ would be valid for all homogeneous isotropic reservoirs under radial flow conditions. Examination of the dimension of each of the generalized groups shows that they are dimensionless. Therefore, dimensionless groups represent a way to generalize the calculated solutions over changes in the reservoir properties. A list of the most widely used dimensionless groups in oilfield units follows:

Dimensionless time,

$$t_D = \frac{0.0002637kt}{\phi\mu c_t r_w^2} \quad (2.4)$$

TABLE 2.1—PRESSURE DROP AT TWO OFFSET WELLS

Measurement at Well B		Measurements at Well C	
Time (hours)	Pressure Drop (psi)	Time (hours)	Pressure Drop (psi)
0.0	0.0	0.0	0.0
24	2.10	24	0.42
48	2.72	48	0.83
72	3.09	72	1.12
96	3.35	96	1.35
120	3.54	120	1.52
144	3.71	144	1.67
168	3.85	168	1.80
192	3.97	192	1.91
216	4.08	216	2.02
240	4.18	240	2.10
		480	2.72
		720	3.09

Dimensionless pressure,

$$p_D = \frac{kh(p_i - p_{r,t})}{141.2qB\mu} \quad \text{(2.5)}$$

Dimensionless radius,

$$r_D = \frac{r}{r_w} \quad \text{(2.6)}$$

Slight variations of these dimensionless groups may be used. For example, dimensionless time may be defined by using the drainage area of Well A instead of the square of the wellbore radius. As will be seen throughout the monograph, plots using dimensionless variables can be used to show general solutions under various flow conditions.

2.4 General Description of Well Test Analysis Procedure

The solution described by Eq. 2.1 is called the line source solution. It describes the pressure at any point in the reservoir at any time as a result of a single change in the flow rate at the center of the radial system. The equation describes the radial flow regime. If the pressure is calculated at radius r_w (the wellbore radius) using the reservoir properties (k, μ, etc.), the results should match the pressure measured with a gauge placed in the wellbore, as illustrated in **Fig. 2.2.** If customary oilfield units were used, Eq. 2.1 could be expressed as Eq. 2.7. This is the main concept of well test analysis. The objective is to find the properties that will make the mathematical model that describes the reservoir match the measured response from the well. In this regard, well test analysis is no different from other inverse problem solutions (e.g., history matching of reservoir performance using wellbore pressure and flow rates of various phases). These problems are called inverse problems because, as schematically shown in **Fig. 2.3,** the user knows the input (flow rate change) and output (pressure change) and needs to calculate the properties of the system that are consistent with this combination. In contrast to the inverse problem, the direct (or forward) problem is the situation in which the user knows the system properties and the input and is trying to calculate the output. Examples of the direct problem include predicting the well performance once the properties are obtained from well test analysis, or predicting the future reservoir performance based on the description obtained from history matching. The direct problem is characterized by having only one solution. However, multiple solutions (reservoir system properties) may be valid for a given set of input and output parameters in an inverse problem.

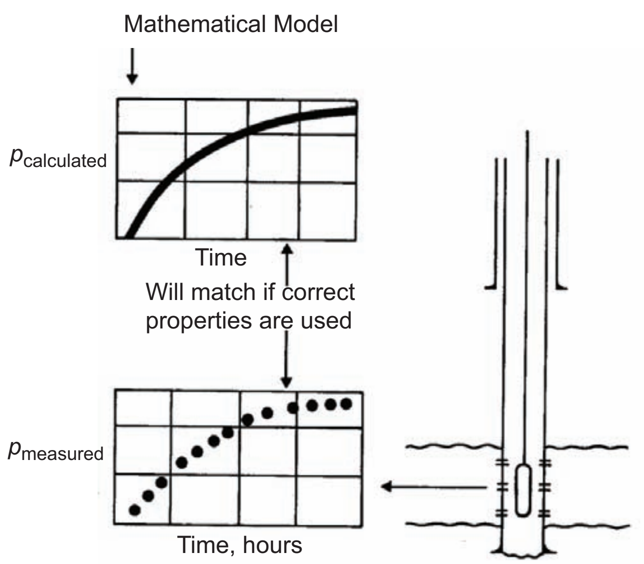

Fig. 2.2—Main concept of well-test analysis.

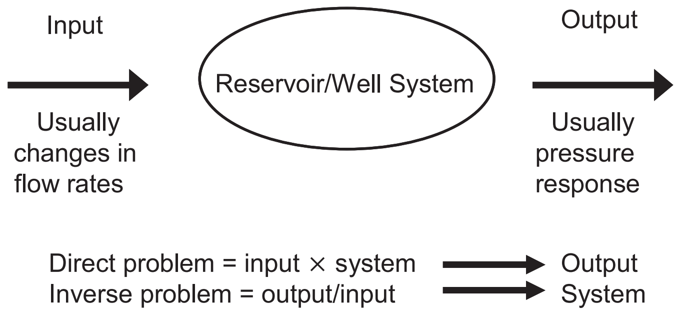

Fig. 2.3—Schematic of the direct and inverse problems.

$$p(r_w,t) = p_i + \frac{70.6qBu}{kh}\mathrm{Ei}\left[\frac{-\phi\mu c_t r_w^2}{4(0.0002637)kt}\right] \qquad (2.7)$$

This difficulty is referred to as nonuniqueness and, in the case of well test analysis, it requires the petroleum engineer to use other sources of information about the reservoir system (e.g., geologic descriptions, cores, or logs) to perform a valid analysis. Transient testing data should not be interpreted in a vacuum. A list of pressures vs. time is never sufficient to analyze a well test.

Matching the measured pressure during a transient test with a mathematical model usually involves a process with four main steps:

1. Examination of the data for obvious errors and invalid readings.
2. Identifying the various flow regimes exhibited by the pressure response to determine the best model that probably will fit the data.
3. Calculating initial values of various reservoir system properties. Usually each flow regime yields certain properties (e.g., the radial flow regime may indicate the values of permeability and skin, whereas the linear flow regime may yield the value of a fracture length).
4. Using the mathematical reservoir model identified in Step 2 and the initial values from Step 3, regression analysis is performed to find the best properties that match the entire set of well test data.

The above four steps (shown schematically in **Fig. 2.4**) represent the state of the art of well test analysis as this monograph is being written. They are completely different from the semilog plot analyses described in Matthews and Russell (1967) and the type-curve matching procedure described by Earlougher (1977). However, they use both of these concepts during the analysis. Future research probably will change this process again (e.g., artificial-intelligence technology may make the second step more computer-dependent, and numerical models (simulators) may gradually replace the analytical models currently used). Continuous research and development in testing tools and methods also will alter the future of well testing.

2.5 Types of Transient Tests

Transient tests, or well tests, are used during the various stages of reservoir discovery, development, and production. Drillstem tests (DSTs) and wireline formation tests are run in exploration and appraisal wells; drawdown, buildup, interference, and pulse tests are run during primary, secondary, and enhanced recovery stages; and step-rate, injectivity, falloff, interference, and pulse tests are run during secondary and enhanced recovery stages. Other specialized tests such as multilayer and vertical permeability tests are run throughout the life of the reservoir. **Table 2.2** lists the various reservoir system properties that can be obtained from each test (Kamal et al. 1995).

2.6 Flow Regimes

In this section, an introduction to various flow regimes is presented. Each flow regime will be discussed in appropriate detail in one of the subsequent chapters. Flow regimes will be presented in the probable order in which they appear in a typical well test. This is the order in which they affect the pressure gauge, or from the

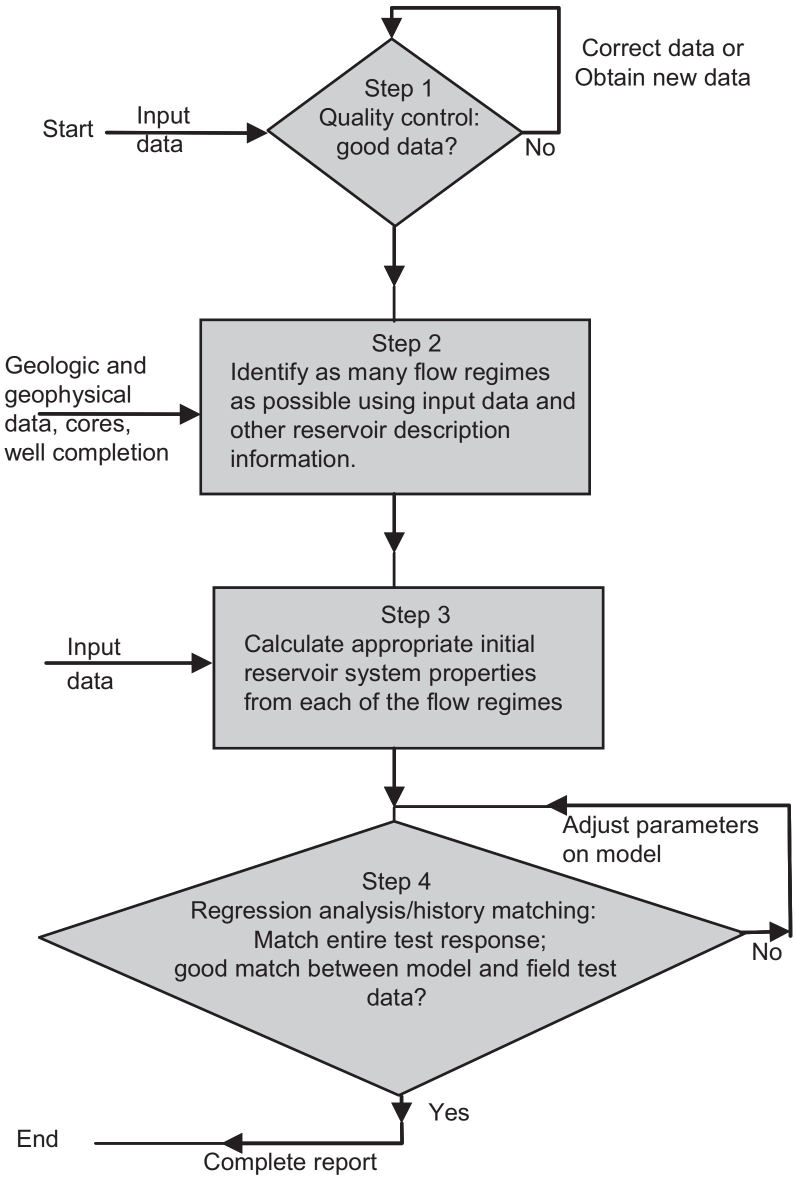

Fig. 2.4—Well-testing-analysis process.

center of the wellbore outward. Flow regimes are identified by the characteristics they exhibit on various graphs or plots. One plot of the pressure change after the beginning of the test and the logarithmic time derivative of this pressure change vs. time on a log-log graph is called the diagnostic plot. Several flow regimes are identifiable on this plot. In addition, each flow regime is identifiable on a specific graph of pressure or pressure change vs. a specific function of time. It is advisable that both plots be examined to identify a given flow regime.

2.6.1 Testing Time and Pressure. For the remainder of this chapter, the terms testing time and pressure change will be used. Testing time (Δt) refers to the elapsed time since the beginning of the test. The test may be a drawdown or buildup test in producing wells or an injectivity or falloff test in injection wells. Pressure change is the absolute value of the pressure at any time during the test minus the pressure at the beginning of the test. Therefore, the pressure change will always increase with testing time, regardless of the type of test.

TABLE 2.2—RESERVOIR PROPERTIES OBTAINABLE FROM VARIOUS TRANSIENT TESTS (AFTER KAMAL et al. 1995)

DSTs	Reservoir behavior
	Fluid samples
	Permeability
	Skin
	Fracture length
	Reservoir pressure
	Reservoir limit
	Boundaries
Wireline formation tests	Pressure profile
	Fluid samples
	Some reservoir properties
Drawdown tests	Reservoir behavior
	Permeability
	Skin
	Fracture length
	Reservoir limit
	Boundaries
Buildup tests	Reservoir behavior
	Permeability
	Skin
	Fracture length
	Reservoir pressure
	Boundaries
Step-rate tests	Formation parting pressure
	Permeability
	Skin
Falloff tests	Mobility in various banks
	Skin
	Reservoir pressure
	Fracture length
	Reservoir pressure
	Fracture length
	Location of front
	Boundaries
Interference and pulse tests	Communication between wells
	Reservoir type behavior
	Porosity
	Interwell permeability
	Vertical permeability
Layered reservoir tests	Properties of individual layers
	Horizontal permeability
	Vertical permeability
	Skin
	Average layer pressure
	Outer boundaries

2.6.2 Pressure Derivative. One of the functions used in analysis of transient tests is the pressure derivative. This function will be described in detail in Chapter 5. However, a few words about this function are presented here to allow the reader to follow the remainder of this chapter.

Using the first derivative of pressure with respect to the time from the beginning of the test or a function of that time provides the engineer with an additional and powerful tool to differentiate among the various flow regimes. As will be shown in the following sections, the pressure derivative has a characteristic signature for each flow regime. The pressure derivative used in this chapter is the first derivative of pressure with respect to the natural logarithm of the testing time, $dp/d(\ln(t))$. This derivative is also known as the Bourdet derivative (Bourdet 1983).

2.6.3 Wellbore Storage. Wellbore storage is a result of the compressible nature of the fluids in the wellbore (Ramey 1970; Agarwal et al. 1970). Data that are dominated by wellbore storage effects are characterized by a straight-line plot with a slope of unity on the log-log plot of pressure difference and pressure derivative vs. time (Ramey 1970; Agarwal et al. 1970; Bourdet 1983). The values of the pressure difference and the pressure derivative will be the same. The same data also will plot as a straight line on a Cartesian plot of pressure or pressure difference vs. time. **Fig. 2.5** shows the log-log and Cartesian plots of the wellbore-storage flow regime.

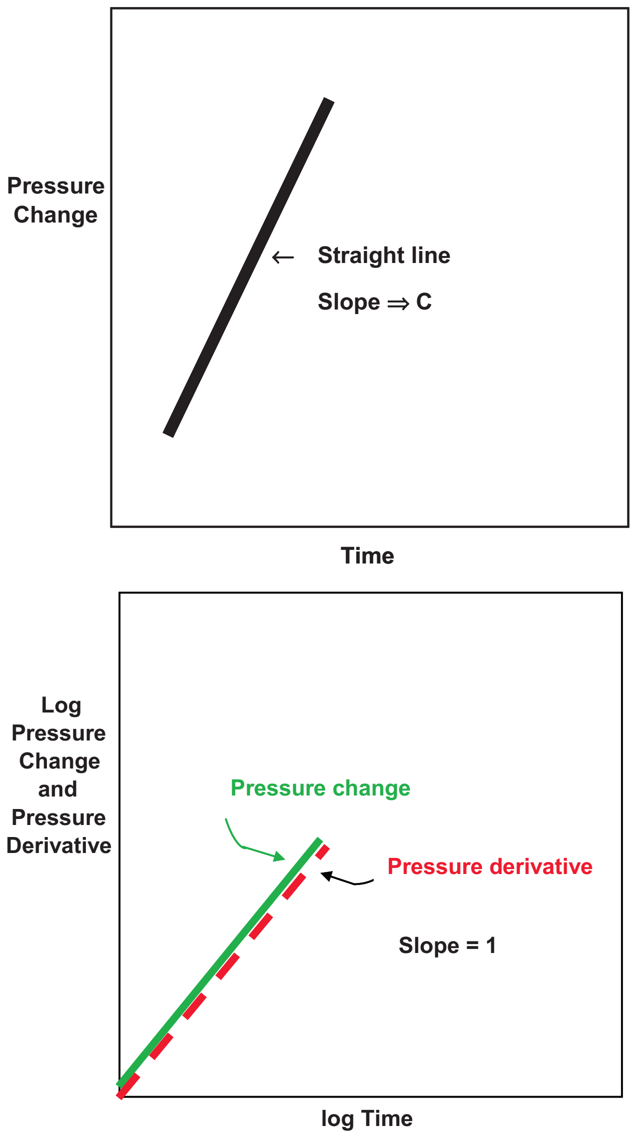

Fig. 2.5—Wellbore-storage flow regime on Cartesian and diagnostic plots.

The early-time Cartesian plot, in addition to its use to identify and analyze the wellbore-storage flow regime, also may be used to detect tool problems and to correct the starting time and pressure of the test.

Visual inspection of the data on a Cartesian plot enables the engineer to recognize whether tool problems were encountered during the test. A smooth plot of pressure vs. time usually indicates a good test. Oscillations in data, gaps in data, or presence of multiple out-of-sync or bad points should raise a warning flag that inaccurate data might have been collected. It should be noted that not all data points that fail to fit the "expected" behavior are necessarily incorrect. Care must be taken in identifying which data points are bad. The engineer should delete the bad data points and continue with the analysis. If it appears that several data points are erroneous, then a major malfunction of the tool might have happened, and it may be advisable to refrain from analyzing the data.

Correct initial time and pressure are probably the most important data for a successful analysis. Because log-log plots of Δp vs. Δt are normally used, it is clear that errors in t_i and p_i would affect the interpretation of the test; t_i and p_i are the initial time and pressure, respectively, at the beginning of the test. Therefore, it is imperative that a correct value of (t_i, p_i) be used. To make this correction, the wellbore storage effects can be used. If the initial time and pressure are incorrect, the log-log plot will not yield a straight line with unit slope. The Cartesian plot will still yield a straight line; however, the straight line will not intersect the pressure axis at time zero at the initial pressure. The initial time should be corrected so that the straight line will intersect the value of p_i at time zero. This is illustrated in **Fig. 2.6,** where the Straight Line A indicates a correct measurement of the initial time and pressure, whereas the Straight Line B indicates a situation in which the initial time was not correctly measured.

For Straight Line B, a correction of Δt_1 is needed. The last data point lying fully on the early-time straight line represents the end of the wellbore-storage-dominated data. The same point should be the last data point on the unit-slope straight line on the log-log plot of pressure difference vs. time.

The wellbore storage coefficient, *C,* is calculated from the data lying on the early-time Cartesian straight line using Eq. 2.8, where Δt and Δp are the coordinates of any of the data points lying on the straight line:

$$C = \frac{qB\Delta t}{24\Delta p} \quad \text{(2.8)}$$

2.6.4 Linear Flow. Linear flow occurs around the tested well as a result of different configurations such as the early-time flow resulting when a fracture (usually hydraulic) intersects the wellbore (Clark 1968; Raghavan et al. 1972; Gringarten et al. 1974) or the late-time flow through a channel caused by two parallel no-flow boundaries (Raghavan et al. 1972). Actually, there are two types of linear flow that occur while testing fractured wells. This phenomenon will be discussed in more detail in Chapter 11. During linear flow, a plot of pressure vs. the square root of testing time yields a straight line. Analysis of such a straight line gives

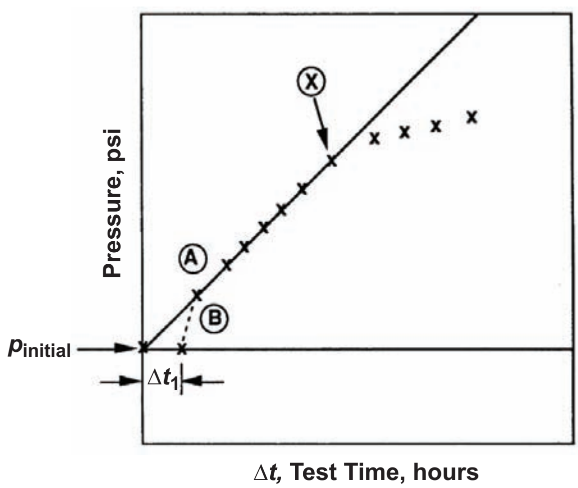

Fig. 2.6—Early-time Cartesian plot.

information about the length of the fracture, the presence of skin on the face of the fracture, or the width of the flow channel. The pressure difference and the pressure derivative of the same data when plotted vs. the test time on a log-log graph yield straight lines with a slope of 0.5. More aptly, the value of the pressure derivative will be half that of the pressure difference. **Fig. 2.7** shows the plots of the linear flow regime. It should be noted, however, that if there is skin (positive or negative) on the face of the fracture, the plot of the pressure change vs. testing time on the log-log plot will not yield a half-slope line.

When the tested well intersects a fracture, linear flow occurs during the early part of the test following the wellbore-stage-flow regime. This linear flow can be expressed by Eq. 2.9:

$$p_{ws} = p_i - \frac{4.064qB}{h}\sqrt{\frac{\mu\Delta t}{k\phi c_t x_f^2}} \quad (2.9)$$

It is clear from this equation that a plot of pressure vs. the square root of Δt yields a straight line. The slope of this line is inversely proportional to half the fracture length, x_f. The intercept gives the value of the pressure drop due to skin on the face of the fracture (Δp_{ffskin}). Therefore, such a plot should be viewed during the

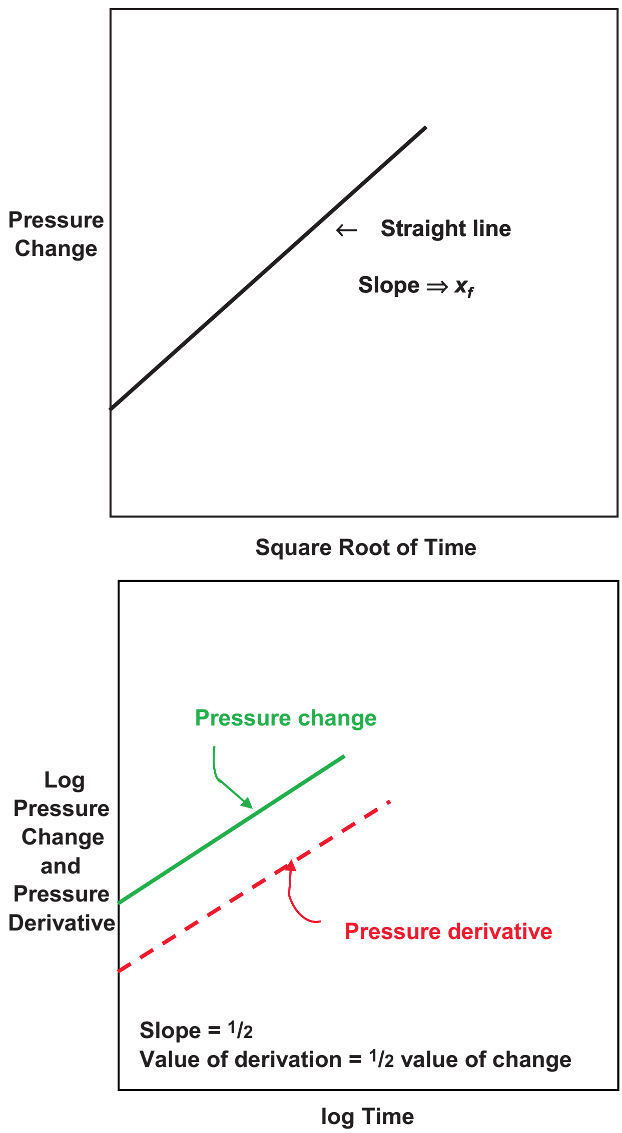

Fig. 2.7—Linear flow regime on diagnostic and square-root-of-time plots.

analysis of pressure-transient tests. **Fig. 2.8** illustrates that the slope of the line is related to the fracture length, and the location of the line indicates whether a skin exists on the face of the fracture.

Plotting Δp or p' vs. Δt on a log-log plot yields a straight line with a slope of 0.5 if linear flow exists. For Δp, this is true only if no skin exists on the face of the fracture. In the presence of skin, the log-log plot of Δp vs. t will yield a line with a slope less than 0.5. If such a graph is viewed without the square-root-of-time plot, the presence of a fracture may be overlooked during the interpretation. The limitation of the square-root-of-time plot is that plotting the data in this manner tends to squeeze the points, giving the appearance of a straight line even though the trend of the data may be slightly curved. It is recommended that an expanded scale be used for the data through this period.

If the well is located between two parallel no-flow boundaries (a channel), linear flow will occur at late time following radial flow (Tiab and Kumar 1980). The characteristics of the late-time linear flow are the same as those of the linear flow generated in a fractured well. In this case, the width of the channel can be calculated from Eq. 2.10:

$$L_{ch} = \frac{0.6374}{m_{lf}} \sqrt{\frac{m_{rf} qB}{\phi c_t h}} \quad \text{(2.10)}$$

It is important to note that to calculate the fracture length on the width of the channel (Eqs. 2.9 and 2.10), the value of the formation permeability must be known. This point will be discussed further in Section 2.6.5.

2.6.5 Bilinear Flow. Bilinear flow occurs at early time during testing of wells that are hydraulically fractured with a finite-conductivity fracture (Cinco-Ley et al. 1978). During this regime, the fluid flows in two perpendicular linear directions (hence the term bilinear flow). One direction is inside the fracture parallel to its length. The other is in the formation perpendicular to the length of the fracture. A Cartesian plot of pressure or pressure difference vs. the fourth root of testing time yields a straight line for a flow period dominated by bilinear flow. The same data points, if plotted on a log-log plot of the pressure difference or pressure derivative vs. testing time, will yield a straight line with a slope of 0.25. Moreover, the value of the pressure derivative will be one-fourth the value of the pressure difference. **Fig. 2.9** shows the log-log plot and the fourth-root-of-time plot for bilinear flow.

The slope of the straight line on the fourth-root-of-time plot is used to calculate the conductivity of the fracture, $k_f w$, using Eq. 2.11:

$$k_f w = \frac{1945.8}{\sqrt{\phi \mu c_t} k} \left(\frac{qB\mu}{h m_{bf}} \right)^2 \quad \text{(2.11)}$$

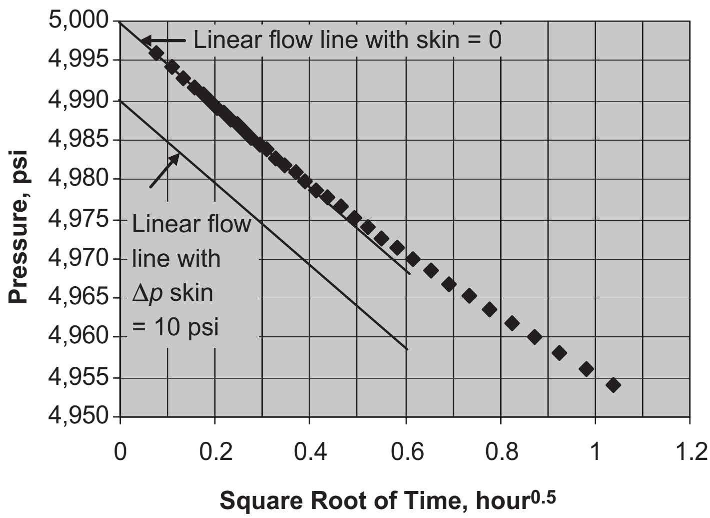

Fig 2.8—Square-root-of-time plot.

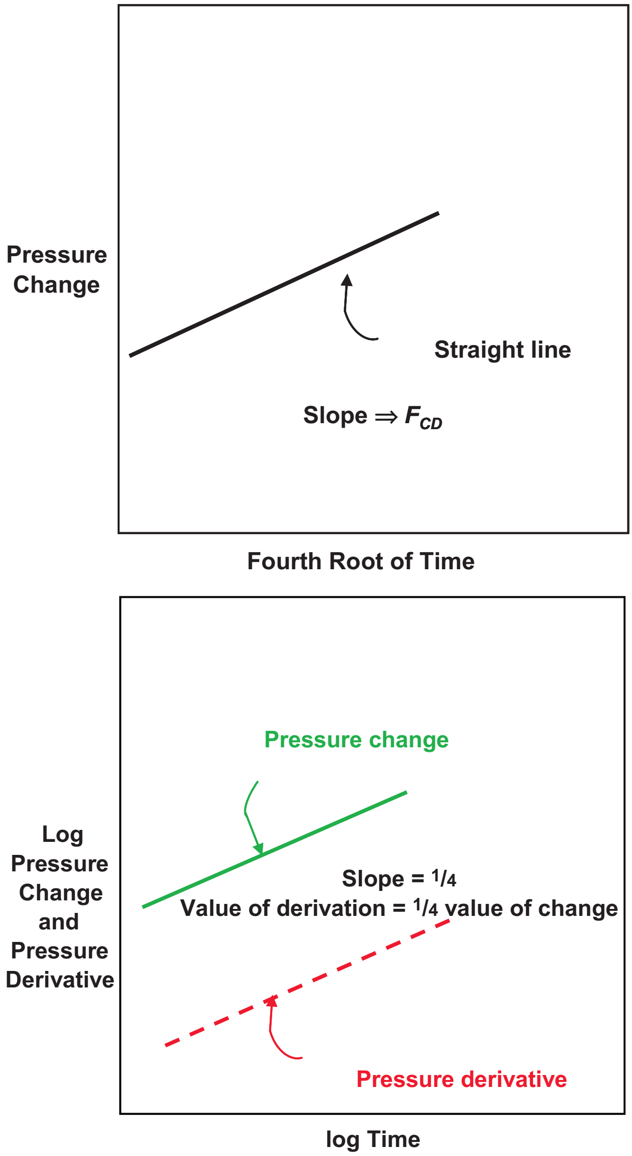

Fig. 2.9—Bilinear flow regime on diagnostic and fourth-root-of-time plots.

The diagnostic (log-log) plot also may be used to calculate numerically the slope of the fourth-root-of-time straight line and the fracture conductivity. The limitation of this analysis can be seen by inspecting Eq. 2.11. To calculate the fracture conductivity, a value for the formation permeability is needed. In reservoirs of extremely low permeability (less than 0.1 md), it is difficult to calculate the formation permeability from a pressure-transient test after the well has been fractured. The reason is that it would take a prohibitively long time to reach the radial-flow state, where the formation permeability can be calculated, as will be explained in Section 2.6.7, in low-permeability reservoirs, where wells usually are stimulated with long fractures. Therefore, it is strongly recommended that a pressure-transient test be run before the well is fractured to enable the engineer to estimate the formation permeability. Once the formation permeability has been determined, the well can be fractured. Subsequent pressure-transient tests on the well will yield needed information about the fracture length and its conductivity using the formation permeability value previously determined.

2.6.6 Spherical Flow. Spherical flow occurs when the flow from the formation to the wellbore is channeled through a short set of perforations or through the small probe of a wireline formation tester (Streltsova 1988).

The characteristic slope of spherical flow is $t^{-1/2}$. A plot of pressure or pressure difference vs. the reciprocal of the square root of time will yield a straight line. The same data will exhibit a slope of –0.5 for the pressure derivative on the diagnostic log-log plot. **Fig. 2.10** shows plots for spherical flow.

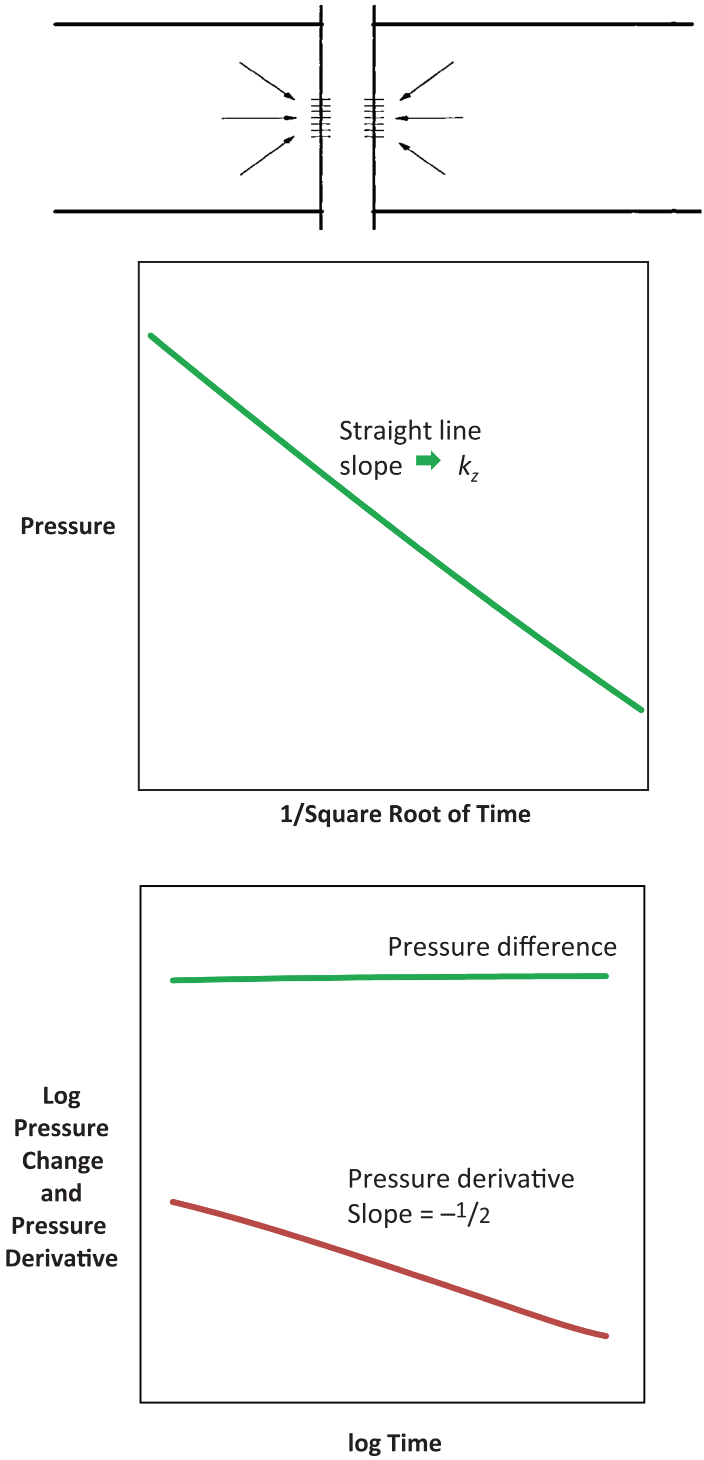

Fig. 2.10—Spherical flow on diagnostic and reciprocal of square-root-of-time plots.

Eq. 2.12 describes spherical flow. It illustrates that the formation vertical permeability may be estimated (assuming the horizontal permeability is known) during the spherical flow regime by using the slope of the reciprocal square-root-of-time straight line:

$$\left(p_i - p_w\right) = 2{,}453 \frac{qB\mu^{3/2}\sqrt{\phi c_t}}{k\sqrt{k_z}} t^{-1/2} + \text{Constant} \quad \text{(2.12)}$$

Spherical flow regimes usually do not last for a long time. Therefore, their use to calculate vertical permeability is not common.

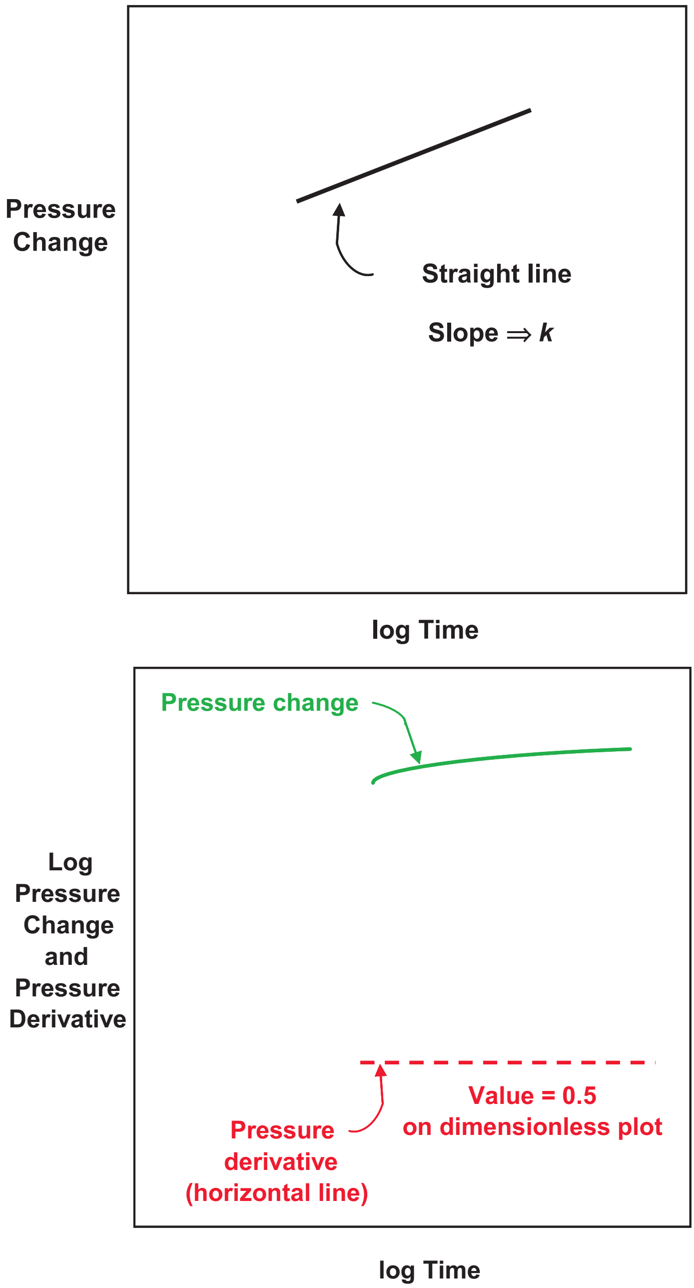

Fig. 2.11—Radial flow regime on diagnostic and semilog plots.

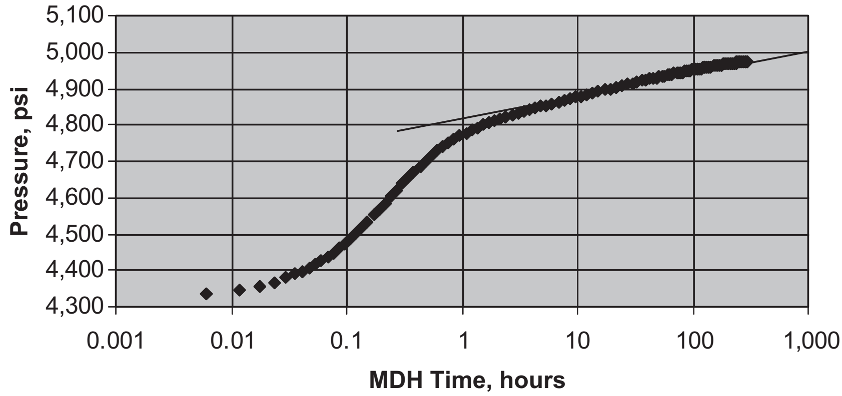

Fig. 2.12—Miller-Dyes-Hutchinson plot.

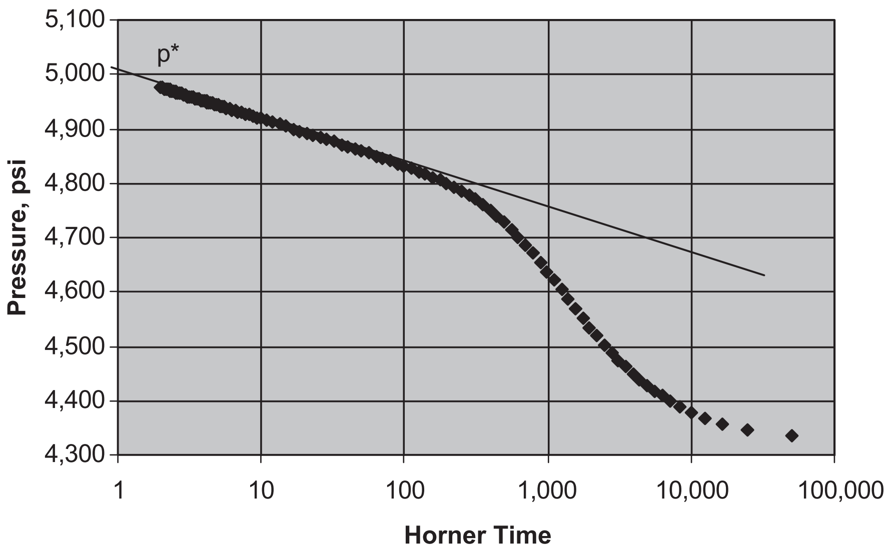

Fig. 2.13—Horner plot.

2.6.7 Radial Flow. The radial flow regime is probably the most important. From this flow regime, the formation permeability, average pressure, and wellbore skin can be calculated. Another name often used for radial flow is infinite-acting radial flow, which refers to the period in the test after the near-wellbore effects have diminished and before the outer boundary effects are felt, in which the pressure is dominated by radial flow in the formation. Radial flow is characterized by a zero slope for the pressure derivative on the diagnostic (log-log) plot **(Fig. 2.11).** The formation permeability can be calculated from the value of the pressure derivative when it becomes flat (slope of zero), and the wellbore skin can be calculated from the separation between the pressure derivative and the pressure difference. The specialized plot for the radial flow is the semilog plot in which the pressure is plotted on the Cartesian (arithmetic) axis and a function of the testing time is plotted on the log axis. Semilog plots are the traditional method of analyzing pressure-transient tests. Several forms of semilog plots were described in the literature in the 1940s through the 1960s. The most famous plots of this type are the Miller-Dyes-Hutchinson plot (Miller et al. 1950) **(Fig. 2.12)** and the Horner plot (Horner 1951) **(Fig. 2.13).** Until the late 1960s and early 1970s, semilog plots were the only type of plots used to analyze pressure-transient tests. Today, although other forms of plotting the data are available, semilog plots remain an integral part of the analysis process.

In semilog plots, the time or a time function is plotted on a log axis on the horizontal scale and the pressure or pressure difference is plotted on a Cartesian axis on the vertical scale. In drawdown or injectivity tests, the testing time is plotted on the log scale. In buildup or falloff tests, either the testing time may be plotted on the log scale [and in this case, the plot is called the Miller-Dyes-Hutchinson (MDH) plot], or Horner time is plotted on the log axis (and in this case, the plot is called a Horner plot). Horner time is defined as $(t_p+\Delta t)/\Delta t$, where t_p is the production time and Δt is the shut-in time. The slope of the straight line formed by the data at late testing time, the value of the intercept of this straight line at testing time of one hour, and the pressure on that straight line at a Horner time of one are the three variables usually obtained from a semilog plot.

The slope of the semilog straight line can be used to calculate the formation permeability using Eq. 2.13:

$$k = \frac{162.6qBu}{m_{rf}h} \quad \text{(2.13)}$$

The value of the pressure at the intercept of this semilog straight line at testing time of 1 hour is called p_{1hr}. The skin at the well can be calculated from this value using Eq. 2.14:

$$s = 1.1513\left[\frac{p_{1hr} - p_w(\Delta t = 0)}{m_{rf}} - \log\left(\frac{k}{\phi \mu c_t r_w^2}\right) + 3.2275\right] \quad \text{(2.14)}$$

In the case of buildup or falloff tests, the value of the pressure at the intercept of the semilog straight line at Horner time of one, which indicates the testing pressure if the well is shut in for an extremely long time in a reservoir of infinite extent, is called p^*. The value of the average reservoir pressure in the drainage area of the well can be calculated from p^*.

There are several advantages to semilog plots. Perhaps the primary advantage is that they are simple to use. All that is required is a plot of the field data on a semilog graph and identification of the straight line reflecting the formation and well properties. Another advantage of semilog plots is that they usually form smooth curves. As will be discussed in Chapter 5, when the test data are plotted on the diagnostic log-log plot, especially when the pressure derivative is used, scatter in the data may make it difficult to perform an accurate analysis. Even in these situations, semilog plots usually yield smooth curves from which a straight line can easily be identified.

The biggest limitation of semilog plots is that they do not give information about which part of the data should be used to draw the correct semilog straight line. An inspection of several semilog plots leads to the conclusion that several straight lines may be drawn. There is a need to identify which one of these lines actually reflects the properties of the formation. Semilog plots by themselves do not provide such information. The engineer should use the diagnostic log-log plot to identify the correct semilog straight line where the pressure derivative has a slope of zero (flat line). Once the correct semilog straight line has been identified, semilog plots may be used to draw this line and compute the formation properties. However, the same information can be obtained also from the log-log diagnostic plot if the pressure derivative is not noisy.

2.6.8 Pseudosteady-State Flow Regime. Pseudosteady state refers to the flow condition in which all outer boundaries have been encountered in a closed reservoir and the formation is undergoing depletion. In this case, the pressure changes at the same rate everywhere in the reservoir. One can think of a pseudosteady-state flow regime as the wellbore storage flow regime in which the fluid in the wellbore is being depleted to produce the well before flow from the formation begins.

As for wellbore storage, the diagnostic log-log plot for pseudosteady state in a drawdown or an injectivity test shows the pressure difference and the pressure derivative exhibiting unit-slope straight lines and the pressure derivative line coinciding with the pressure difference line at late time. Also like the wellbore storage flow regime, the specialized plot for pseudosteady state is the Cartesian plot. As wellbore storage yields information about the volume of the wellbore, pseudosteady state yields information about the volume of the reservoir and, to a lesser extent, its shape. **Fig. 2.14** shows various plots of pseudosteady state.

If, during a drawdown test, the well is allowed to flow long enough, the reservoir outer boundary eventually starts to control the flowing bottomhole pressure (Jones 1956, 1957). In the case of a no-flow (closed) outer boundary, the well reaches pseudosteady state. At this point, the pressure everywhere in the reservoir starts to decline at a constant rate, assuming that the flow rate is constant at the producing well.

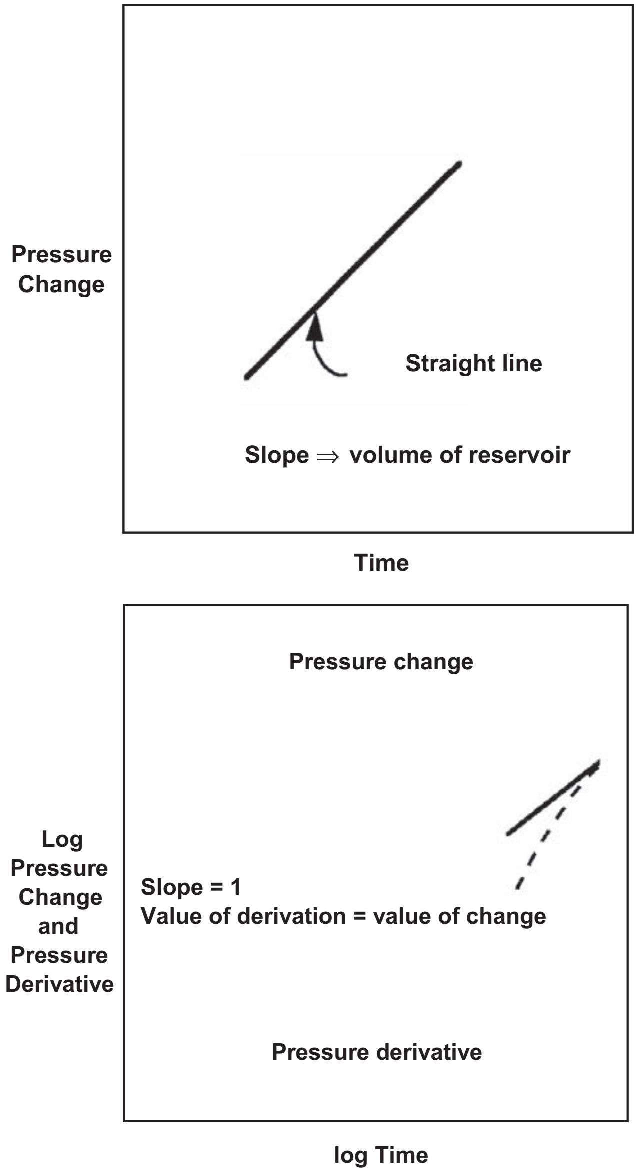

Fig. 2.14—Pseudosteady-state flow regime on diagnostic and late-time Cartesian plots.

The straight line on the Cartesian plot of Fig. 2.14 has slope m^* and an intercept p_{int} at testing time zero on the pressure axis. The reservoir volume may be obtained from the slope of the late-Cartesian-plot straight line using Eq. 2.15:

$$\phi hA = \frac{0.23395qB}{c_t m^*} \quad \text{(2.15)}$$

A shape factor, C_A, reflecting the shape of the reservoir, may be obtained from the intercept of the late-time Cartesian-plot straight line and the characteristics of the semilog straight line described in Chapter 5 (Earlougher 1971). To obtain the shape factor, Eq. 2.16 is used:

$$C_A = 5.456\frac{m_{rf}}{m^*}e\left[\frac{2.303(\Delta p_{1\text{hr}} - \Delta p_{\text{int}})}{m_{rf}}\right] \quad \text{(2.16)}$$

Late-time Cartesian plots calculate the reservoir volume in drawdown tests that run long enough to reach the reservoir outer boundaries. The limitation of late-time Cartesian plots is that the calculated shape factor should be used with caution. To calculate the shape factor, an exponential equation must be used. Therefore, a small error in any one of the parameters of the exponential function will yield large errors in the values of the shape factor.

2.6.9 Other Flow Regimes. Other flow regimes, which are usually variations of those discussed above, may exist during well testing. In the following chapters of this monograph, details of other, less common flow regimes are discussed. For example, the transition flow regimes of naturally fractured systems are discussed in Chapter 10. **Table 2.3** summarizes some of the common flow regimes and their representations on various plots (Kamal et al. 1995).

2.7 Pseudopressure

In the development of the diffusivity equation with the line source solution shown in Eq. 2.1, the equation of state used is based on a fluid of constant compressibility. This assumption holds for gases over only a very small pressure range (much smaller than the pressure change during a pressure-transient test). Therefore, a different diffusivity equation is needed for gas wells.

The appropriate equation of state for a gas is:

$$pV = ZnRT \quad \text{.......} \quad (2.17)$$

This can also be rewritten as:

$$pV = \frac{mZRT}{M}, \quad \text{.......} \quad (2.18)$$

where m is the mass and M the molecular weight of the gas.

Replacing the density with the mass divided by the volume yields:

$$\rho = \frac{Mp}{ZRT} \quad \text{.......} \quad (2.19)$$

Using the above equation of state to derive the diffusivity equation governing gas flow in porous media suggests that to solve the gas diffusivity equation accurately, the pressure and the effect of pressure variation on viscosity and z-factor must be considered. Although over some pressure ranges the liquid equations can be used to model gas behavior and over other ranges a pressure-squared form can be used, the correct method of analyzing gas wells over all ranges of pressure is through the real gas potential or gas pseudopressure function, $m(p)$. The real gas potential is defined as (Al-Hussainy et al. 1966; Russell et al. 1966):

$$m(p) = 2\int_{p_b}^{p} \frac{p}{\mu Z}\,dp, \quad \text{.......} \quad (2.20)$$

where p_b is some base pressure, usually 14.7 psia.

The gas pseudopressure function, $m(p)$, as a function of pressure, can be determined by taking laboratory viscosity and z-factor data, graphing, and integrating. Correlations also may be used. Computer codes are available to calculate $m(p)$. Note that unless the gas composition changes during the producing life (the reservoir conditions pass through the two-phase envelope), one $m(p)$ vs. pressure curve can be used for the life of the reservoir. When $m(p)$ is used, the gas diffusivity equation reduces to the constant-compressibility liquid diffusivity equation with $m(p)$ as the variable instead of p. This means that the relationships and procedures developed for liquid wells all apply for gas wells. For example, data dominate the wellbore storage plot as a unit-slope log-log line when $m(p)$ is graphed vs. Δt.

The values of the pseudopressure function are usually in the order of 10^7 psi^2/cp. As a convenience, to use values similar to normal pressures, the pseudopressure sometimes is normalized by dividing it by the initial reservoir pressure. The resulting function is called the normalized pseudopressure function.

TABLE 2.3—PLOTS AND FLOW REGIMES OF TRANSIENT TESTS (AFTER KAMAL et al. 1995)

	Plot					
Flow Regime	Cartesian	$1/\sqrt{\Delta t}$	$\sqrt{\Delta t}$	$\sqrt[4]{\Delta t}$	Log-Log	Semilog
Wellbore storage	Straight line				Unit slope on Δp and p'	Positive s
	Slope → C				Δp and p' coincide	Negative s
	Intercept → Δt_C					
	Δp_C					
Spherical flow		Straight line			Slope = – ½ on p'	
		Slope = m_{sf} $\rightarrow\sqrt{k_r k_z}$				
Linear flow			Straight line		Slope = ½ on p' and on Δp if $s = 0$	
			Slope = $m_{lf} \rightarrow L_f$			
			Intercept → fracture damage		Slope < ½ on Δp if $s \neq 0$	
					p' at half the level of Δp	
Bilinear flow				Straight line	Slope = ¼	
				Slope = $m_{bf} \rightarrow C_{fd}$	p' at ¼ level of Δp	
First IARF (high-permeability layer, fractures)	Decreasing slope				p' at horizontal	Straight line
					at $p'_D = 0.5$	Slope = $m \rightarrow kh$
						$\Delta p_{1hr} \rightarrow s$
Transition	More decreasing slope				$\Delta p = \lambda e^{-2s}$ or B'	Straight line
					$p'_D = 0.25$ (transition)	Slope = $m/2$ (transition)
					= < 0.25 (pseudosteady state)	= 0 (pseudosteady state)
Second IARF (total system)	Similar slope to first IARF				p' horizontal at p'_D = 0.5	Straight line
						Slope = $m \rightarrow kh, p^*$
						$\Delta p_{1hr} \rightarrow s$
Single no-flow boundary					p' horizontal at p'_D = 1.0	Straight line
						Slope = $2m$
						Intersection with IARF → distance to boundary
Outer no-flow boundaries (drawdown tests only)	Straight line				Unit slope for Δp and p'	Increasing slope
	Slope = $m^* \rightarrow \Phi A h$				Δp and p' coincide	
	$p_{int} \rightarrow C_A$					

2.8 Skin Effects

Skin effects will be discussed in detail in Chapter 6. For completeness of the basic concepts of transient testing, it is sufficient to note that the most common method of representing damage or improvement to the wellbore is through the skin factor *s* (van Everdingen 1953; Hurst 1953). The skin factor is simply the dimensionless pressure drop due to variation in the wellbore condition. Using Eq. 2.5, *s* may be described as:

$$s = \frac{kh\Delta p_s}{141.2qBu} \quad (2.21)$$

The skin factor is a composite of several factors, as represented by Eq. 2.22:

$$s = s_{\text{dam}} + s_{\text{pen}} + s_{\text{perf}} + s_{\text{turb}} + s_{\text{frac}} + s_{\text{swp}} \quad (2.22)$$

2.9 Non-Darcy Flow

The right side of Eq. 2.22 can be separated into rate-dependent and rate-independent skin factors:

$$s = s' + s_{\text{turb}}, \quad (2.23)$$

where s' is the sum of the rate-independent skin factors. Eq. 2.23 can be rewritten as

$$s = s' + Dq, \quad (2.24)$$

where D is the turbulence coefficient. Inspection of Eq. 2.24 reveals that when turbulent flow is encountered, *s* is a linear function of *q* (i.e., the skin due to turbulence is a linear function of rate). Consequently, when a well flowing at high rate is tested at two different rates, different values of *s* should be obtained when the tests are analyzed. This observation has led to the following suggested procedure for evaluating turbulence:

1. Determine *s* from two or more independent flow tests.
2. Plot *s* vs. *q* on Cartesian paper; this plot is shown in **Fig. 2.15.**
3. Compute the slope of the skin plot. From Eq. 2.24, it is obvious that *D* = slope.
4. Determine the intercept value of *s*; this is equal to s'.

The turbulence factor can also be measured in the laboratory or predicted theoretically. However, these methods are considered inadequate for the purpose of evaluating field test data.

2.10 Summary

Transient well testing is a reservoir description and evaluation method used to obtain dynamic reservoir properties. It is a valuable tool that, like all other indirect determination methods, should be used with understanding of the physical concepts behind well testing and the inherent nonuniqueness of the solutions. Transient well

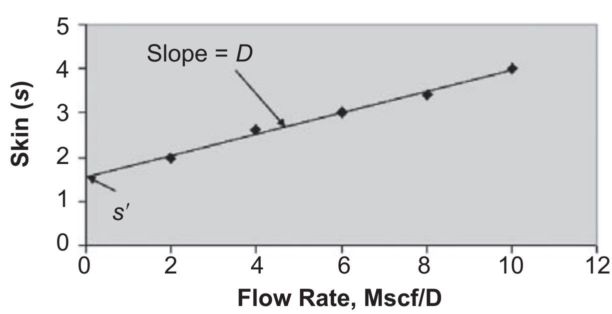

Fig. 2.15—Non-Darcy flow skin.

testing should be used with a complete understanding of the geological and operational aspects of the field. It is often necessary to run several types of transient tests and to integrate their results with other characterization methods to obtain a valid description of the reservoir (Kamal et al. 1995; Kamal 1979). Interpretation of well tests relies on identifying various flow regimes, calculating initial reservoir system properties from these flow regimes, and history matching the entire test through use of an appropriate reservoir model, initial estimates, and regression analysis. Most of the models currently in use are analytical, but the technology is moving toward the use of numerical modeling.

Nomenclature

m_{bf} = slope of bilinear-flow straight line, psi/$\sqrt[4]{\text{time}}$
m_{lf} = slope of linear-flow straight line, psi/$\sqrt{\text{time}}$
m_{rf} = slope of radial-flow straight line, psi/cycle
R = gas constant
Z = real gas deviation factor
Δp_{int} = intercept of Cartesian plot pseudosteady-state straight line, psi

Subscripts
dam = damage
frac = fracture
pen = penetration
perf = perforation

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