PRENTICE HALL

PETROLEUM PRODUCTION SYSTEMS

SECOND EDITION

MICHAEL J. ECONOMIDES
A. DANIEL HILL
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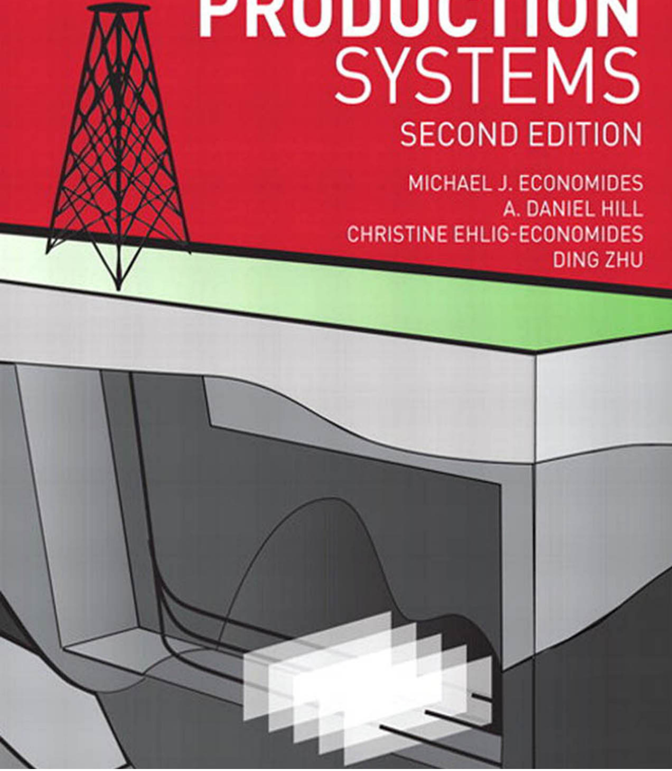

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Contents

Foreword xv
Preface xvii
About the Authors xix

Chapter 1 The Role of Petroleum Production Engineering 1
- 1.1 Introduction 1
- 1.2 Components of the Petroleum Production System 2
  - 1.2.1 Volume and Phase of Reservoir Hydrocarbons 2
  - 1.2.2 Permeability 8
  - 1.2.3 The Zone near the Well, the Sandface, and the Well Completion 9
  - 1.2.4 The Well 10
  - 1.2.5 The Surface Equipment 11
- 1.3 Well Productivity and Production Engineering 11
  - 1.3.1 The Objectives of Production Engineering 11
  - 1.3.2 Organization of the Book 14
- 1.4 Units and Conversions 15
- References 18

Chapter 2 Production from Undersaturated Oil Reservoirs 19
- 2.1 Introduction 19
- 2.2 Steady-State Well Performance 19
- 2.3 Transient Flow of Undersaturated Oil 24
- 2.4 Pseudosteady-State Flow 26
  - 2.4.1 Transition to Pseudosteady State from Infinite Acting Behavior 29
- 2.5 Wells Draining Irregular Patterns 30
- 2.6 Inflow Performance Relationship 34
- 2.7 Effects of Water Production, Relative Permeability 37
- 2.8 Summary of Single-Phase Oil Inflow Performance Relationships 39
- References 39
- Problems 39

Chapter 3 Production from Two-Phase Reservoirs 41

3.1 Introduction 41
3.2 Properties of Saturated Oil 42
  3.2.1 General Properties of Saturated Oil 42
  3.2.2 Property Correlations for Two-Phase Systems 47
3.3 Two-Phase Flow in a Reservoir 53
3.4 Oil Inflow Performance for a Two-Phase Reservoir 55
3.5 Generalized Vogel Inflow Performance 56
3.6 Fetkovich's Approximation 57
References 58
Problems 58

Chapter 4 Production from Natural Gas Reservoirs 61

4.1 Introduction 61
  4.1.1 Gas Gravity 61
  4.1.2 Real Gas Law 63
4.2 Correlations and Useful Calculations for Natural Gases 66
  4.2.1 Pseudocritical Properties from Gas Gravity 66
  4.2.2 Presence of Nonhydrocarbon Gases 68
  4.2.3 Gas Compressibility Factor Correction for Nonhydrocarbon Gases 68
  4.2.4 Gas Viscosity 71
  4.2.5 Gas Formation Volume Factor 74
  4.2.6 Gas Isothermal Compressibility 75
4.3 Approximation of Gas Well Deliverability 76
4.4 Gas Well Deliverability for Non-Darcy Flow 79
4.5 Transient Flow of a Gas Well 84
References 91
Problems 93

Chapter 5 Production from Horizontal Wells 95

5.1 Introduction 95
5.2 Steady-State Well Performance 97
  5.2.1 The Joshi Model 97
  5.2.2 The Furui Model 100
5.3 Pseudosteady-State Flow 103

5.3.1 The Babu and Odeh Model 103
5.3.2 The Economides et al. Model 109
5.4 Inflow Performance Relationship for Horizontal Gas Wells 114
5.5 Two-Phase Correlations for Horizontal Well Inflow 115
5.6 Multilateral Well Technology 116
References 117
Problems 119

Chapter 6 The Near-Wellbore Condition and Damage Characterization; Skin Effects 121
6.1 Introduction 121
6.2 Hawkins' Formula 122
6.3 Skin Components for Vertical and Inclined Wells 126
6.4 Skin from Partial Completion and Well Deviation 128
6.5 Horizontal Well Damage Skin Effect 134
6.6 Well Completion Skin Factors 138
6.6.1 Cased, Perforated Completions 138
6.6.2 Slotted or Perforated Liner Completions 146
6.6.3 Gravel Pack Completions 148
6.7 Formation Damage Mechanisms 151
6.7.1 Particle Plugging of Pore Spaces 151
6.7.2 Mechanisms for Fines Migration 154
6.7.3 Chemical Precipitation 154
6.7.4 Fluid Damage: Emulsions, Relative Permeability, and Wettability Changes 155
6.7.5 Mechanical Damage 156
6.7.6 Biological Damage 157
6.8 Sources of Formation Damage During Well Operations 157
6.8.1 Drilling Damage 157
6.8.2 Completion Damage 159
6.8.3 Production Damage 161
6.8.4 Injection Damage 162
References 163
Problems 165

Chapter 7 Wellbore Flow Performance **167**
7.1 Introduction 167
7.2 Single-Phase Flow of an Incompressible, Newtonian Fluid 168
  7.2.1 Laminar or Turbulent Flow 168
  7.2.2 Velocity Profiles 169
  7.2.3 Pressure-Drop Calculations 172
  7.2.4 Annular Flow 179
7.3 Single-Phase Flow of a Compressible, Newtonian Fluid 179
7.4 Multiphase Flow in Wells 184
  7.4.1 Holdup Behavior 185
  7.4.2 Two-Phase Flow Regimes 187
  7.4.3 Two-Phase Pressure Gradient Models 191
  7.4.4 Pressure Traverse Calculations 210
References 214
Problems 215

Chapter 8 Flow in Horizontal Wellbores, Wellheads, and Gathering Systems **217**
8.1 Introduction 217
8.2 Flow in Horizontal Pipes 217
  8.2.1 Single-Phase Flow: Liquid 217
  8.2.2 Single-Phase Flow: Gas 218
  8.2.3 Two-Phase Flow 220
  8.2.4 Pressure Drop through Pipe Fittings 236
8.3 Flow through Chokes 236
  8.3.1 Single-Phase Liquid Flow 240
  8.3.2 Single-Phase Gas Flow 241
  8.3.3 Gas–Liquid Flow 243
8.4 Surface Gathering Systems 247
8.5 Flow in Horizontal Wellbores 250
  8.5.1 Importance of Wellbore Pressure Drop 250
  8.5.2 Wellbore Pressure Drop for Single-Phase Flow 252
  8.5.3 Wellbore Pressure Drop for Two-Phase Flow 252
References 256
Problems 258

Chapter 9 Well Deliverability **261**
9.1 Introduction 261
9.2 Combination of Inflow Performance Relationship (IPR) and Vertical Flow Performance (VFP) 262
9.3 IPR and VFP of Two-Phase Reservoirs 268
9.4 IPR and VFP in Gas Reservoirs 270
Problems 274

Chapter 10 Forecast of Well Production **275**
10.1 Introduction 275
10.2 Transient Production Rate Forecast 275
10.3 Material Balance for an Undersaturated Reservoir and Production Forecast Under Pseudosteady-State Conditions 277
10.4 The General Material Balance for Oil Reservoirs 281
  10.4.1 The Generalized Expression 281
  10.4.2 Calculation of Important Reservoir Variables 282
10.5 Production Forecast from a Two-Phase Reservoir: Solution Gas Drive 286
10.6 Gas Material Balance and Forecast of Gas Well Performance 294
References 296
Problems 297

Chapter 11 Gas Lift **299**
11.1 Introduction 299
11.2 Well Construction for Gas Lift 299
11.3 Continuous Gas-Lift Design 303
  11.3.1 Natural versus Artificial Flowing Gradient 303
  11.3.2 Pressure of Injected Gas 304
  11.3.3 Point of Gas Injection 305
  11.3.4 Power Requirements for Gas Compressors 309
11.4 Unloading Wells with Multiple Gas-Lift Valves 310
11.5 Optimization of Gas-Lift Design 312
  11.5.1 Impact of Increase of Gas Injection Rate, Sustaining of Oil Rate with Reservoir Pressure Decline 312
  11.5.2 Maximum Production Rate with Gas Lift 314

11.6 Gas-Lift Performance Curve 316
11.7 Gas-Lift Requirements versus Time 328
References 332
Problems 333

Chapter 12 Pump-Assisted Lift 335
12.1 Introduction 335
12.2 Positive-Displacement Pumps 338
12.2.1 Sucker Rod Pumping 338
12.2.2 Progressing Cavity Pumps 352
12.3 Dynamic Displacement Pumps 354
12.3.1 Electrical Submersible Pumps 354
12.4 Lifting Liquids in Gas Wells; Plunger Lift 359
References 362
Problems 362

Chapter 13 Well Performance Evaluation 365
13.1 Introduction 365
13.2 Open-Hole Formation Evaluation 366
13.3 Cased Hole Logs 368
13.3.1 Cement Evaluation 368
13.3.2 Cased Hole Formation Evaluation 369
13.3.3 Production Log Evaluation 370
13.4 Transient Well Analysis 387
13.4.1 Rate Transient Analysis 387
13.4.2 Wireline Formation Testing and Formation Fluid Sampling 390
13.4.3 Well Rate and Pressure Transient Analysis 393
13.4.4 Flow Regime Analysis 400
References 438
Problems 439

Chapter 14 Matrix Acidizing: Acid/Rock Interactions 443
14.1 Introduction 443
14.2 Acid–Mineral Reaction Stoichiometry 446
14.3 Acid–Mineral Reaction Kinetics 453
14.3.1 Laboratory Measurement of Reaction Kinetics 454
14.3.2 Reactions of HCl and Weak Acids with Carbonates 454

14.3.3 Reaction of HF with Sandstone Minerals 455
14.3.4 Reactions of Fluosilicic Acid with Sandstone Minerals 460
14.4 Acid Transport to the Mineral Surface 460
14.5 Precipitation of Acid Reaction Products 461
References 464
Problems 466

Chapter 15 Sandstone Acidizing Design 469
15.1 Introduction 469
15.2 Acid Selection 470
15.3 Acid Volume and Injection Rate 472
15.3.1 Competing Factors Influencing Treatment Design 472
15.3.2 Sandstone Acidizing Models 472
15.3.3 Monitoring the Acidizing Process, the Optimal Rate Schedule 486
15.4 Fluid Placement and Diversion 496
15.4.1 Mechanical Acid Placement 496
15.4.2 Ball Sealers 497
15.4.3 Particulate Diverting Agents 497
15.4.4 Viscous Diversion 508
15.5 Preflush and Postflush Design 509
15.5.1 The HCl Preflush 509
15.5.2 The Postflush 511
15.6 Acid Additives 512
15.7 Acidizing Treatment Operations 512
References 513
Problems 516

Chapter 16 Carbonate Acidizing Design 519
16.1 Introduction 519
16.2 Wormhole Formation and Growth 522
16.3 Wormhole Propagation Models 525
16.3.1 The Volumetric Model 526
16.3.2 The Buijse-Glasbergen Model 529
16.3.3 The Furui et al. Model 531
16.4 Matrix Acidizing Design for Carbonates 535
16.4.1 Acid Type and Concentration 535

16.4.2 Acid Volume and Injection Rate 536
16.4.3 Monitoring the Acidizing Process 538
16.4.4 Fluid Diversion in Carbonates 540
16.5 Acid Fracturing 541
16.5.1 Acid Penetration in Fractures 542
16.5.2 Acid Fracture Conductivity 545
16.5.3 Productivity of an Acid-Fractured Well 552
16.5.4 Comparison of Propped and Acid Fracture Performance 553
16.6 Acidizing of Horizontal Wells 554
References 555
Problems 558

Chapter 17 Hydraulic Fracturing for Well Stimulation 559
17.1 Introduction 559
17.2 Length, Conductivity, and Equivalent Skin Effect 562
17.3 Optimal Fracture Geometry for Maximizing the Fractured Well Productivity 566
17.3.1 Unified Fracture Design 567
17.4 Fractured Well Behavior in Conventional Low-Permeability Reservoirs 574
17.4.1 Infinite Fracture Conductivity Performance 574
17.4.2 Finite Fracture Conductivity Performance 578
17.5 The Effect of Non-Darcy Flow on Fractured Well Performance 579
17.6 Fractured Well Performance for Unconventional Tight Sand or Shale Reservoirs 585
17.6.1 Tight Gas Sands 586
17.6.2 Shale 586
17.7 Choke Effect for Transverse Hydraulic Fractures 592
References 594
Problems 597

Chapter 18 The Design and Execution of Hydraulic Fracturing Treatments 601
18.1 Introduction 601
18.2 The Fracturing of Reservoir Rock 602
18.2.1 *In-Situ* Stresses 602
18.2.2 Breakdown Pressure 604
18.2.3 Fracture Direction 606

18.3 Fracture Geometry 609
  18.3.1 Hydraulic Fracture Width with the PKN Model 610
  18.3.2 Fracture Width with a Non-Newtonian Fluid 613
  18.3.3 Fracture Width with the KGD Model 614
  18.3.4 Fracture Width with the Radial Model 615
  18.3.5 Tip Screenout (TSO) Treatments 615
  18.3.6 Creating Complex Fracture Geometries 615
18.4 The Created Fracture Geometry and Net Pressure 616
  18.4.1 Net Fracturing Pressure 616
  18.4.2 Height Migration 621
  18.4.3 Fluid Volume Requirements 624
  18.4.4 Proppant Schedule 629
  18.4.5 Propped Fracture Width 631
18.5 Fracturing Fluids 635
  18.5.1 Rheological Properties 636
  18.5.2 Frictional Pressure Drop during Pumping 641
18.6 Proppants and Fracture Conductivity 642
  18.6.1 Propped Fracture Conductivity 643
  18.6.2 Proppant Transport 645
18.7 Fracture Diagnostics 646
  18.7.1 Fracturing Pressure Analysis 646
  18.7.2 Fracture Geometry Measurement 647
18.8 Fracturing Horizontal Wells 651
  18.8.1 Fracture Orientation in Horizontal Well Fracturing 651
  18.8.2 Well Completions for Multiple Fracturing 652
References 655
Problems 657

Chapter 19 Sand Management 661
19.1 Introduction 661
19.2 Sand Flow Modeling 662
  19.2.1 Factors Affecting Formation Sand Production 662
  19.2.2 Sand Flow in the Wellbore 672
19.3 Sand Management 676
  19.3.1 Sand Production Prevention 676
  19.3.2 Cavity Completion 677

19.4 Sand Exclusion 677
19.4.1 Gravel Pack Completion 678
19.4.2 Frac-Pack Completion 688
19.4.3 High-Performance Fracturing 693
19.4.4 High-Performance Fractures in Deviated Production Wells 694
19.4.5 Perforating Strategy for High-Performance Fractures 697
19.5 Completion Failure Avoidance 698
References 699
Problems 702

Appendix A 703

Appendix B 705

Appendix C 709

Index 711

Foreword

I have waited on this book for the last 10 years. It is a modernized version of the classic first edition, thousands of copies of which have been distributed to my former trainees, engineers, and associates. The authors of the book have worked with me in a number of capacities for 25 years and we have become kindred spirits both in how we think about oil and gas production enhancement and, especially, in knowing how bad production management can be, even in the most unexpected places and companies.

It is a comprehensive book that describes the "production system," or what I refer to as "nodal analysis," artificial lift, well diagnosis, matrix stimulation, hydraulic fracturing, and sand control.

There are some important points that are made in this book, which I have made repeatedly in the past:

1. To increase field production, well improvement can be more effective than infill drilling, especially when the new wells are just as suboptimum as existing wells. We demonstrated this while I was managing Yukos E&P in Russia. During that time appropriate production enhancement actions improved field production by more than 15% even after stopping all drilling for as long as a year.
2. In conventional reservoirs, optimized well completions do not sacrifice ultimate field recovery as long as they are achieved with adequate reservoir pressure support from either natural gas cap or water drive mechanisms or through injection wells.
3. Many, if not most, operators fail to address well performance, and few wells are produced at their maximum flow potential. This book takes great steps to show that proper production optimization is far more important to success than just simply executing blindly well completions and even stimulation practices. In particular, I consider the Unified Fracture Design (UFD) approach, the brainchild of the lead author, to be the only coherent approach to hydraulic fracture design. I have been using it exclusively and successfully in all my hydraulic fracture design work.

This book provides not only best practices but also the rationale for new activities. The strategies shown in this book explain why unconventional oil and gas reservoirs are successfully produced today.

The book fills a vacuum in the industry and has come not a moment too soon.

—Joe Mach
Inventor, Nodal Analysis
Former Executive VP, Yukos
Former VP, Schlumberger

Preface

Since the first edition of this book appeared in 1994, many advances in the practice of petroleum production engineering have occurred. The objective of this book is the same as for the first edition: to provide a comprehensive and relatively advanced textbook in petroleum production engineering, that suffices as a terminal exposure to senior undergraduates or an introduction to graduate students. This book is also intended to be used in industrial training to enable nonpetroleum engineers to understand the essential elements of petroleum production. Numerous technical advances in the years since the first edition have led to the extensive revisions that readers will notice in this second edition. In particular, widespread use of horizontal wells and much broader application of hydraulic fracturing have changed the face of production practices and justified critical updating of the text. The authors have benefited from wide experience in both university and industrial settings. Our areas of interest are complementary and ideally suited for this book, spanning classical production engineering, well testing, production logging, artificial lift, and matrix and hydraulic fracture stimulation. We have been contributors in these areas for many years. Among the four of us, we have taught petroleum production engineering to literally thousands of students and practicing engineers using the first edition of this book, both in university classes and in industry short courses, and this experience has been one of the key guiding factors in the creation of the second edition.

This book offers a structured approach toward the goal defined above. Chapters 2–4 present the inflow performance for oil, two-phase, and gas reservoirs. Chapter 5 deals with complex well architecture such as horizontal and multilateral wells, reflecting the enormous growth of this area of production engineering since the first edition of the book. Chapter 6 deals with the condition of the near-wellbore zone, such as damage, perforations, and gravel packing. Chapter 7 covers the flow of fluids to the surface. Chapter 8 describes the surface flow system, flow in horizontal pipes, and flow in horizontal wells. Combination of inflow performance and well performance versus time, taking into account single-well transient flow and material balance, is shown in Chapters 9 and 10. Therefore, Chapters 1–10 describe the workings of the reservoir and well systems.

Gas lift is outlined in Chapter 11, and mechanical lift in Chapter 12. For an appropriate production engineering remedy it is essential that well and reservoir diagnosis be done. Chapter 13 presents the state-of-the-art in modern diagnosis that includes well testing, production logging, and well monitoring with permanent downhole instruments.

From the well diagnosis it can be concluded whether the well is in need of matrix stimulation, hydraulic fracturing, artificial lift, combinations of the above, or none. Matrix stimulation for all major types of reservoirs is presented in Chapters 14, 15, and 16, while hydraulic fracturing is treated in Chapters 17 and 18. Chapter 19 is a new chapter dealing with advances in sand management.

To simplify the presentation of realistic examples, data for three characteristic reservoir types—an undersaturated oil reservoir, a saturated oil reservoir, and a gas reservoir—are presented in the Appendixes. These data sets are used throughout the book.

Revising this textbook to include the primary production engineering of the past 20 years has been a considerable task, requiring a long and concerted (and only occasionally contentious!) effort from the authors. We have also benefited from the efforts of many of our graduate students and support staff. Discussions with many of our colleagues in industry and academia have also been a key to the completion of the book. We would like to thank in particular the contributions of Dr. Paul Bommer, who provided some very useful material on artificial lift; Dr. Chen Yang, who assisted with some of the new material on carbonate acidizing; Dr. Tom Blasingame and Mr. Chih Chen, who shared well data used as pressure buildup and production data examples; Mr. Tony Rose, who created the graphics; and Ms. Katherine Brady and Mr. Imran Ali for their assistance in the production of this second edition.

As we did for the first edition, we acknowledge the many colleagues, students, and our own professors who contributed to our efforts. In particular, feedback from all of our students in petroleum production engineering courses has guided our revision of the first edition of this text, and we thank them for their suggestions, comments, and contributions.

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CHAPTER 1

The Role of Petroleum Production Engineering

1.1 Introduction

Petroleum production involves two distinct but intimately connected general systems: the reservoir, which is a porous medium with unique storage and flow characteristics; and the artificial structures, which include the well, bottomhole, and wellhead assemblies, as well as the surface gathering, separation, and storage facilities.

Production engineering is that part of petroleum engineering that attempts to maximize production (or injection) in a cost-effective manner. In the 15 years that separated the first and second editions of this textbook worldwide production enhancement, headed by hydraulic fracturing, has increased tenfold in constant dollars, becoming the second largest budget item of the industry, right behind drilling. Complex well architecture, far more elaborate than vertical or single horizontal wells, has also evolved considerably since the first edition and has emerged as a critical tool in reservoir exploitation.

In practice one or more wells may be involved, but in distinguishing production engineering from, for example, reservoir engineering, the focus is often on specific wells and with a short-time intention, emphasizing production or injection optimization. In contrast, reservoir engineering takes a much longer view and is concerned primarily with recovery. As such, there may be occasional conflict in the industry, especially when international petroleum companies, whose focus is accelerating and maximizing production, have to work with national oil companies, whose main concerns are to manage reserves and long-term exploitation strategies.

Production engineering technologies and methods of application are related directly and interdependently with other major areas of petroleum engineering, such as formation evaluation, drilling, and reservoir engineering. Some of the most important connections are summarized below.

Modern formation evaluation provides a composite reservoir description through three-dimensional (3-D) seismic, interwell log correlation and well testing. Such description leads to the identification of geological flow units, each with specific characteristics. Connected flow units form a reservoir.

Drilling creates the all-important well, and with the advent of directional drilling technology it is possible to envision many controllable well configurations, including very long horizontal sections and multilateral, multilevel, and multibranched wells, targeting individual flow units. The drilling of these wells is never left to chance but, instead, is guided by very sophisticated measurements while drilling (MWD) and logging while drilling (LWD). Control of drilling-induced, near-wellbore damage is critical, especially in long horizontal wells.

Reservoir engineering in its widest sense overlaps production engineering to a degree. The distinction is frequently blurred both in the context of study (single well versus multiple well) and in the time duration of interest (long term versus short term). Single-well performance, undeniably the object of production engineering, may serve as a boundary condition in a fieldwide, long-term reservoir engineering study. Conversely, findings from the material balance calculations or reservoir simulation further define and refine the forecasts of well performance and allow for more appropriate production engineering decisions.

In developing a petroleum production engineering thinking process, it is first necessary to understand important parameters that control the performance and the character of the system. Below, several definitions are presented.

1.2 Components of the Petroleum Production System

1.2.1 Volume and Phase of Reservoir Hydrocarbons

1.2.1.1 Reservoir

The reservoir consists of one or several interconnected geological flow units. While the shape of a well and converging flow have created in the past the notion of radial flow configuration, modern techniques such as 3-D seismic and new logging and well testing measurements allow for a more precise description of the shape of a geological flow unit and the ensuing production character of the well. This is particularly true in identifying lateral and vertical boundaries and the inherent heterogeneities.

Appropriate reservoir description, including the extent of heterogeneities, discontinuities, and anisotropies, while always important, has become compelling after the emergence of horizontal wells and complex well architecture with total lengths of reservoir exposure of many thousands of feet.

Figure 1-1 is a schematic showing two wells, one vertical and the other horizontal, contained within a reservoir with potential lateral heterogeneities or discontinuities (sealing faults), vertical boundaries (shale lenses), and anisotropies (stress or permeability).

While appropriate reservoir description and identification of boundaries, heterogeneities, and anisotropies is important, it is somewhat forgiving in the presence of only vertical wells. These issues become critical when horizontal and complex wells are drilled.

The encountering of lateral discontinuities (including heterogeneous pressure depletion caused by existing wells) has a major impact on the expected complex well production. The well branch trajectories vis à vis the azimuth of directional properties also has a great effect on well production. Ordinarily, there would be only one set of optimum directions.

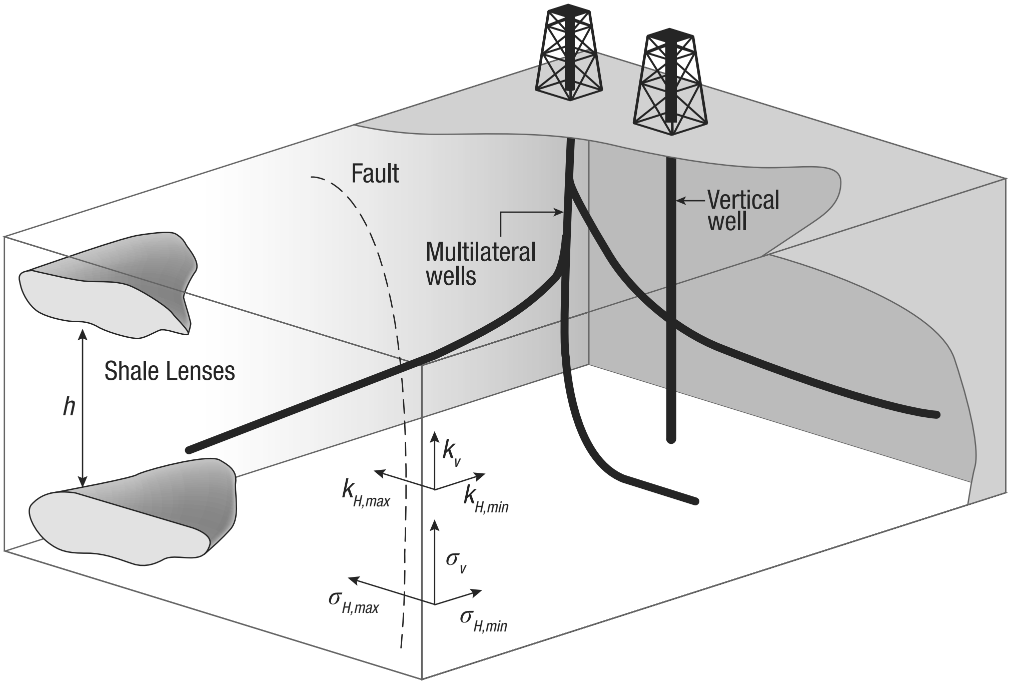

Figure 1-1 Common reservoir heterogeneities, anisotropies, discontinuities, and boundaries affecting the performance of vertical, horizontal, and complex-architecture wells.

Understanding the geological history that preceded the present hydrocarbon accumulation is essential. There is little doubt that the best petroleum engineers are those who understand the geological processes of deposition, fluid migration, and accumulation. Whether a reservoir is an anticline, a fault block, or a channel sand not only dictates the amount of hydrocarbon present but also greatly controls well performance.

1.2.1.2 Porosity

All of petroleum engineering deals with the exploitation of fluids residing within porous media. Porosity, simply defined as the ratio of the pore volume, V_p, to the bulk volume, V_b,

$$\phi = \frac{V_p}{V_b} \tag{1-1}$$

is an indicator of the amount of fluid in place. Porosity values vary from over 0.3 to less than 0.1. The porosity of the reservoir can be measured based on laboratory techniques using reservoir cores or with field measurements including logs and well tests. Porosity is one of the very first measurements obtained in any exploration scheme, and a desirable value is essential for the continuation of any further activities toward the potential exploitation of a reservoir. In the absence of substantial porosity there is no need to proceed with an attempt to exploit a reservoir.

1.2.1.3 Reservoir Height

Often known as “reservoir thickness” or “pay thickness,” the reservoir height describes the thickness of a porous medium in hydraulic communication contained between two layers. These layers are usually considered impermeable. At times the thickness of the hydrocarbon-bearing formation is distinguished from an underlaying water-bearing formation, or aquifer. Often the term “gross height” is employed in a multilayered, but co-mingled during production, formation. In such cases the term “net height” may be used to account for only the permeable layers in a geologic sequence.

Well logging techniques have been developed to identify likely reservoirs and quantify their vertical extent. For example, measuring the spontaneous potential (SP) and knowing that sandstones have a distinctly different response than shales (a likely lithology to contain a layer), one can estimate the thickness of a formation. Figure 1-2 is a well log showing clearly the deflection of the spontaneous potential of a sandstone reservoir and the clearly different response of the adjoining shale layers. This deflection corresponds to the thickness of a *potentially* hydrocarbon-bearing, porous medium.

The presence of satisfactory net reservoir height is an additional imperative in any exploration activity.

1.2.1.4 Fluid Saturations

Oil and/or gas are never alone in “saturating” the available pore space. Water is always present. Certain rocks are “oil-wet,” implying that oil molecules cling to the rock surface. More frequently, rocks are “water-wet.” Electrostatic forces and surface tension act to create these wettabilities, which may change, usually with detrimental consequences, as a result of injection of fluids, drilling, stimulation, or other activity, and in the presence of surface-acting chemicals. If the water is present but does not flow, the corresponding water saturation is known as “connate” or “interstitial.” Saturations larger than this value would result in free flow of water along with hydrocarbons.

Petroleum hydrocarbons, which are mixtures of many compounds, are divided into oil and gas. Any mixture depending on its composition and the conditions of pressure and temperature may appear as liquid (oil) or gas or a mixture of the two.

Frequently the use of the terms *oil* and *gas* is blurred. Produced oil and gas refer to those parts of the total mixture that would be in liquid and gaseous states, respectively, after surface separation. Usually the corresponding pressure and temperature are “standard conditions,” that is, usually (but not always) 14.7 psi and 60° F.

Flowing oil and gas in the reservoir imply, of course, that either the initial reservoir pressure or the induced flowing bottomhole pressures are such as to allow the concurrent presence of two phases. Temperature, except in the case of high-rate gas wells, is for all practical purposes constant.

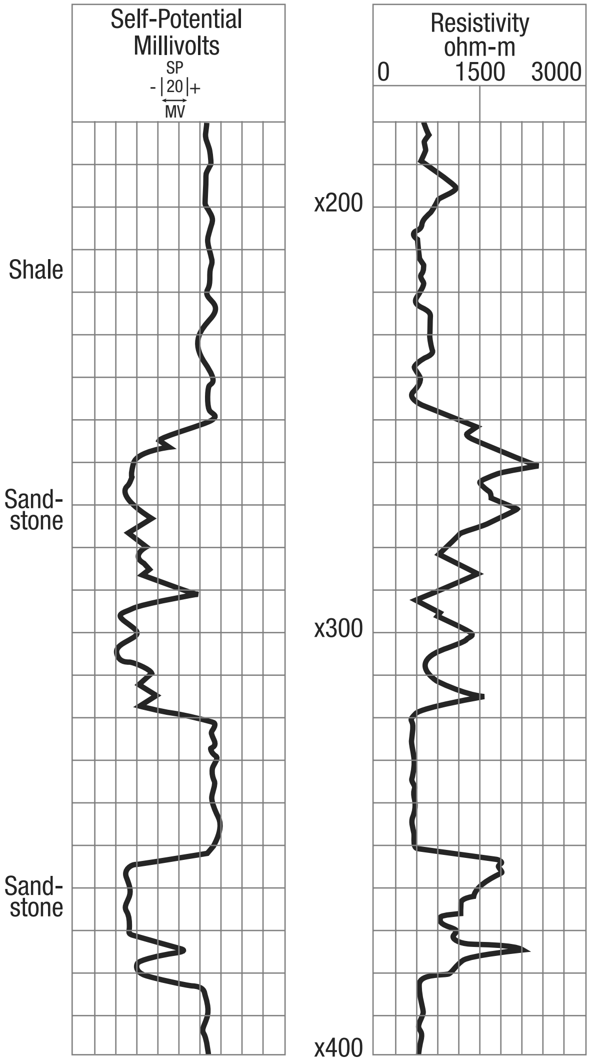

Figure 1-2 Spontaneous potential and electrical resistivity logs identifying sandstones versus shales, and water-bearing versus hydrocarbon-bearing formations.

An attractive hydrocarbon saturation is the third critical variable (along with porosity and reservoir height) to be determined before a well is tested or completed. A classic method, currently performed in a variety of ways, is the measurement of the formation electrical resistivity. Knowing that formation brines are good conductors of electricity (i.e., they have poor resistivity) and hydrocarbons are the opposite, a measurement of this electrical property in a porous formation of sufficient height can detect the presence of hydrocarbons. With proper calibration, not just the presence but also the hydrocarbon saturation (i.e., fraction of the pore space occupied by hydrocarbons) can be estimated.

Figure 1-2 also contains a resistivity log. The previously described SP log along with the resistivity log, showing a high resistivity within the same zone, are good indicators that the identified porous medium is likely saturated with hydrocarbons.

The combination of porosity, reservoir net thickness, and saturations is essential in deciding whether a prospect is attractive or not. These variables can allow the estimation of hydrocarbons near the well.

1.2.1.5 Classification of Reservoirs

All hydrocarbon mixtures can be described by a phase diagram such as the one shown in Figure 1-3. Plotted are temperature (x axis) and pressure (y axis). A specific point is the *critical point*, where the properties of liquid and gas converge. For each temperature less than the critical-point temperature (to the left of T_c in Figure 1-3) there exists a pressure called the "bubble-point" pressure, above which only liquid (oil) is present and below which gas and liquid coexist. For lower pressures (at constant temperature), more gas is liberated. Reservoirs above the bubble-point pressure are called "undersaturated."

If the initial reservoir pressure is less than or equal to the bubble-point pressure, or if the flowing bottomhole pressure is allowed to be at such a value (even if the initial reservoir pressure is above the bubble point), then free gas will at least form and will likely flow in the reservoir. This type of a reservoir is known as "two-phase" or "saturated."

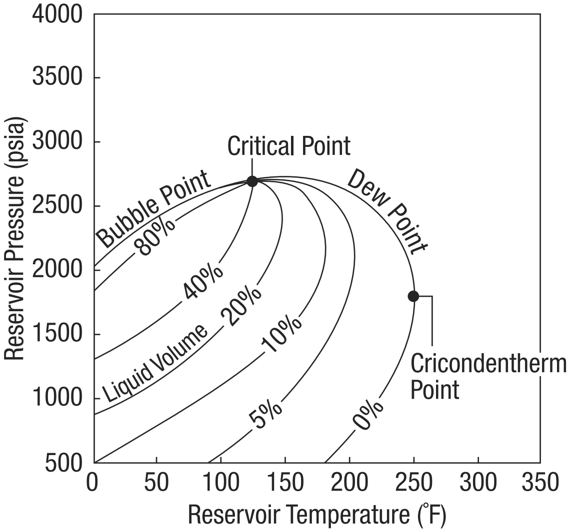

Figure 1-3 Oilfield hydrocarbon phase diagram showing bubble-point and dew-point curves, lines of constant-phase distribution, region of retrograde condensation, and the critical and cricondentherm points.

For temperatures larger than the critical point (to the right of T_c in Figure 1-3), the curve enclosing the two-phase envelop is known as the "dew-point" curve. Outside, the fluid is gas, and reservoirs with these conditions are "lean" gas reservoirs.

The maximum temperature of a two-phase envelop is known as the "cricondentherm." Between these two points there exists a region where, because of the shape of the gas saturation curves, as the pressure decreases, liquid or "condensate" is formed. This happens until a limited value of the pressure, after which further pressure reduction results in revaporization. The region in which this phenomenon takes place is known as the "retrograde condensation" region, and reservoirs with this type of behavior are known as "retrograde condensate reservoirs."

Each hydrocarbon reservoir has a characteristic phase diagram and resulting physical and thermodynamic properties. These are usually measured in the laboratory with tests performed on fluid samples obtained from the well in a highly specialized manner. Petroleum thermodynamic properties are known collectively as *PVT* (*pressure–volume–temperature*) properties.

1.2.1.6 Areal Extent

Favorable conclusions on the porosity, reservoir height, fluid saturations, and pressure (and implied phase distribution) of a petroleum reservoir, based on single well measurements, are insufficient for both the decision to develop the reservoir and for the establishment of an appropriate exploitation scheme.

Advances in 3-D and wellbore seismic techniques, in combination with well testing, can increase greatly the region where knowledge of the reservoir extent (with height, porosity, and saturations) is possible. Discontinuities and their locations can be detected. As more wells are drilled, additional information can enhance further the knowledge of the reservoir's peculiarities and limits.

The areal extent is essential in the estimation of the "original-oil (or gas)-in-place." The hydrocarbon volume, V_{HC}, in reservoir cubic ft is

$$V_{HC} = Ah\phi(1 - S_w) \tag{1-2}$$

where A is the areal extent in ft^2, h is the reservoir thickness in ft, ϕ is the porosity, and S_w is the water saturation. (Thus, $1 - S_w$ is the hydrocarbon saturation.) The porosity, height, and saturation can of course vary within the areal extent of the reservoir.

Equation (1-2) can lead to the estimation of the oil or gas volume under standard conditions after dividing by the oil formation volume factor, B_o, or the gas formation volume factor, B_g. This factor is simply a ratio of the volume of liquid or gas under reservoir conditions to the corresponding volumes under standard conditions. Thus, for oil,

$$N = \frac{7758Ah\phi(1 - S_w)}{B_o} \tag{1-3}$$

where N is in stock tank barrels (STB). In Equation (1-3) the area is in acres. For gas,

$$G = \frac{Ah\phi(1 - S_w)}{B_g} \tag{1-4}$$

where G is in standard cubic ft (SCF) and A is in ft^2.

The gas formation volume factor (traditionally, res ft^3/SCF), B_g, simply implies a volumetric relationship and can be calculated readily with an application of the real gas law. The gas formation volume factor is much smaller than 1.

The oil formation volume factor (res bbl/STB), B_o, is not a simple physical property. Instead, it is an empirical thermodynamic relationship allowing for the reintroduction into the liquid (at the elevated reservoir pressure) of all of the gas that would be liberated at standard conditions. Thus the oil formation volume factor is invariably larger than 1, reflecting the swelling of the oil volume because of the gas dissolution.

The reader is referred to the classic textbooks by Muskat (1949), Craft and Hawkins (revised by Terry, 1991), and Amyx, Bass, and Whiting (1960), and the newer book by Dake (1978) for further information. The present textbook assumes basic reservoir engineering knowledge as a prerequisite.

1.2.2 Permeability

The presence of a substantial porosity usually (but not always) implies that pores will be interconnected. Therefore the porous medium is also "permeable." The property that describes the ability of fluids to flow in the porous medium is permeability. In certain lithologies (e.g., sandstones), a larger porosity is associated with a larger permeability. In other lithologies (e.g., chalks), very large porosities, at times over 0.4, are not necessarily associated with proportionately large permeabilities.

Correlations of porosity versus permeability should be used with a considerable degree of caution, especially when going from one lithology to another. For production engineering calculations these correlations are rarely useful, except when considering matrix stimulation. In this instance, correlations of the *altered* permeability with the *altered* porosity after stimulation are useful.

The concept of permeability was introduced by Darcy (1856) in a classic experimental work from which both petroleum engineering and groundwater hydrology have benefited greatly.

Figure 1-4 is a schematic of Darcy's experiment. The flow rate (or fluid velocity) can be measured against pressure (head) for different porous media.

Darcy observed that the flow rate (or velocity) of a fluid through a specific porous medium is linearly proportional to the head or pressure difference between the inlet and the outlet and a characteristic property of the medium. Thus,

$$u \; \alpha \; k\Delta p \tag{1-5}$$

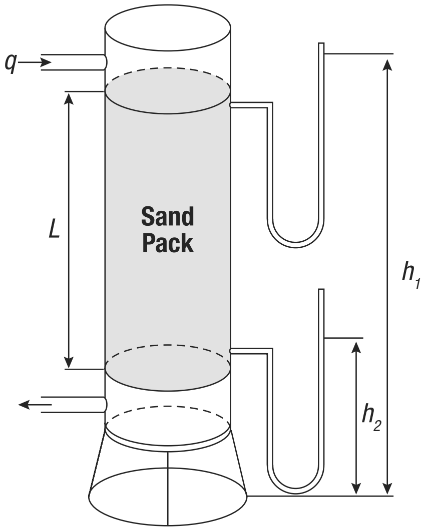

Figure 1-4 Darcy's experiment. Water flows through a sand pack and the pressure difference (head) is recorded.

where k is the permeability and is a characteristic property of the porous medium. Darcy's experiments were done with water. If fluids of other viscosities flow, the permeability must be divided by the viscosity and the ratio k/μ is known as the "mobility."

1.2.3 The Zone near the Well, the Sandface, and the Well Completion

The zone surrounding a well is important. First, even without any man-made disturbance, converging, radial flow results in a considerable pressure drop around the wellbore and, as will be demonstrated later in this book, the pressure drop away from the well varies logarithmically with the distance. This means that the pressure drop in the first foot away from the well is naturally equal to that 10 feet away and equal to that 100 feet away, and so on. Second, all intrusive activities such as drilling, cementing, and well completion are certain to alter the condition of the reservoir near the well. This is usually detrimental and it is not inconceivable that in some cases 90% of the total pressure drop in the reservoir may be consumed in a zone just a few feet away from the well.

Matrix stimulation is intended to recover or even improve the near-wellbore permeability. (There is damage associated even with stimulation. It is the net effect that is expected to be beneficial.) Hydraulic fracturing, today one of the most widely practiced well-completion techniques, alters the manner by which fluids flow to the well; one of the most profound effects is that near-well radial flow and the damage associated with it are eliminated.

Many wells are cemented and cased. One of the purposes of cementing is to support the casing, but at formation depths the most important reason is to provide zonal isolation. Contamination of the produced fluid from the other formations or the loss of fluid *into* other formations

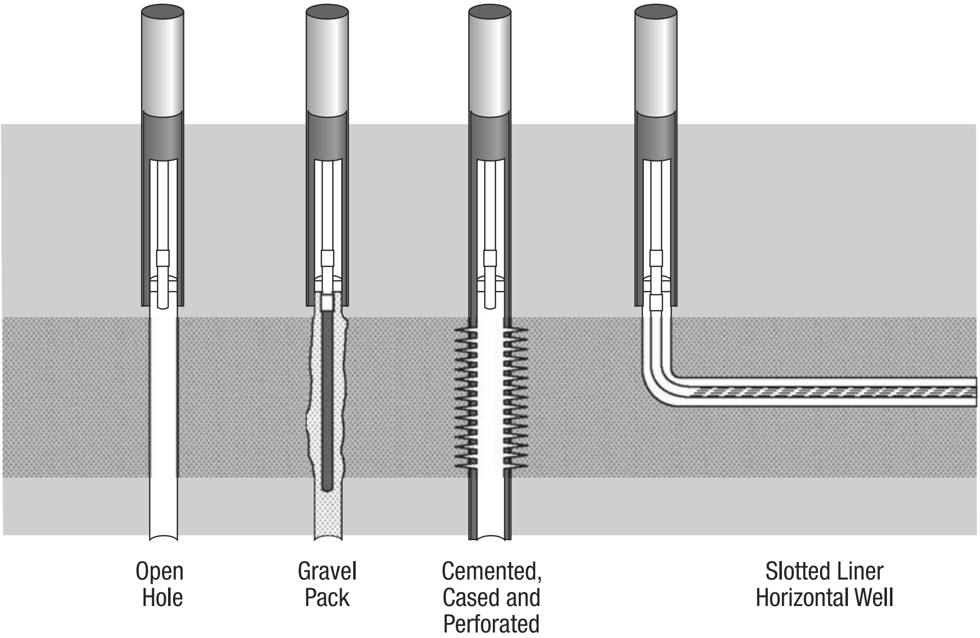

Figure 1-5 Options for well completions.

can be envisioned readily in an open-hole completion. If no zonal isolation or wellbore stability problems are present, the well can be open hole. A cemented and cased well must be perforated in order to reestablish communication with the reservoir. Slotted liners can be used if a cemented and cased well is not deemed necessary and are particularly common in horizontal wells where cementing is more difficult.

Finally, to combat the problems of sand or other fines production, screens can be placed between the well and the formation. Gravel packing can be used as an additional safeguard and as a means to keep permeability-reducing fines away from the well.

The various well completions and the resulting near-wellbore zones are shown in Figure 1-5.

The ability to direct the drilling of a well allows the creation of highly deviated, horizontal, and complex wells. In these cases, a longer to far longer exposure of the well with the reservoir is accomplished than would be the case for vertical wells.

1.2.4 The Well

Entrance of fluids into the well, following their flow through the porous medium, the near-well zone, and the completion assembly, requires that they are lifted through the well up to the surface.

There is a required flowing pressure gradient between the bottomhole and the well head. The pressure gradient consists of the potential energy difference (hydrostatic pressure) and the frictional pressure drop. The former depends on the reservoir depth and the latter depends on the well length.

If the bottomhole pressure is sufficient to lift the fluids to the top, then the well is "naturally flowing." Otherwise, artificial lift is indicated. Mechanical lift can be supplied by a pump. Another technique is to reduce the density of the fluid in the well and thus to reduce the hydrostatic pressure. This is accomplished by the injection of lean gas in a designated spot along the well. This is known as "gas lift."

1.2.5 The Surface Equipment

After the fluid reaches the top, it is likely to be directed toward a manifold connecting a number of wells. The reservoir fluid consists of oil, gas (even if the flowing bottomhole pressure is larger than the bubble-point pressure, gas is likely to come out of solution along the well), and water.

Traditionally, the oil, gas, and water are not transported long distances as a mixed stream, but instead are separated at a surface processing facility located in close proximity to the wells. An exception that is becoming more common is in some offshore fields, where production from subsea wells, or sometimes the commingled production from several wells, may be transported long distances before any phase separation takes place.

Finally, the separated fluids are transported or stored. In the case of formation water it is usually disposed in the ground through a reinjection well.

The reservoir, well, and surface facilities are sketched in Figure 1-6. The flow systems from the reservoir to the entrance to the separation facility are the production engineering systems that are the subjects of study in this book.

1.3 Well Productivity and Production Engineering

1.3.1 The Objectives of Production Engineering

Many of the components of the petroleum production system can be considered together by graphing the inflow performance relationship (IPR) and the vertical flow performance (VFP). Both the IPR and the VFP relate the wellbore flowing pressure to the surface production rate. The IPR represents what the reservoir can deliver, and the VFP represents what the well can deliver. Combined, as in Figure 1-7, the intersection of the IPR with the VFP yields the well deliverability, an expression of what a well will actually produce for a given operating condition. The role of a petroleum production engineer is to maximize the well deliverability in a cost-effective manner. Understanding and measuring the variables that control these relationships (well diagnosis) becomes imperative.

While these concepts will be dealt with extensively in subsequent chapters, it is useful here to present the productivity index, J, of an oil well (analogous expressions can be written for gas and two-phase wells):

$$J = \frac{q}{p - p_{wf}} = \frac{kh}{\alpha_r B\mu} J_D. \tag{1-6}$$

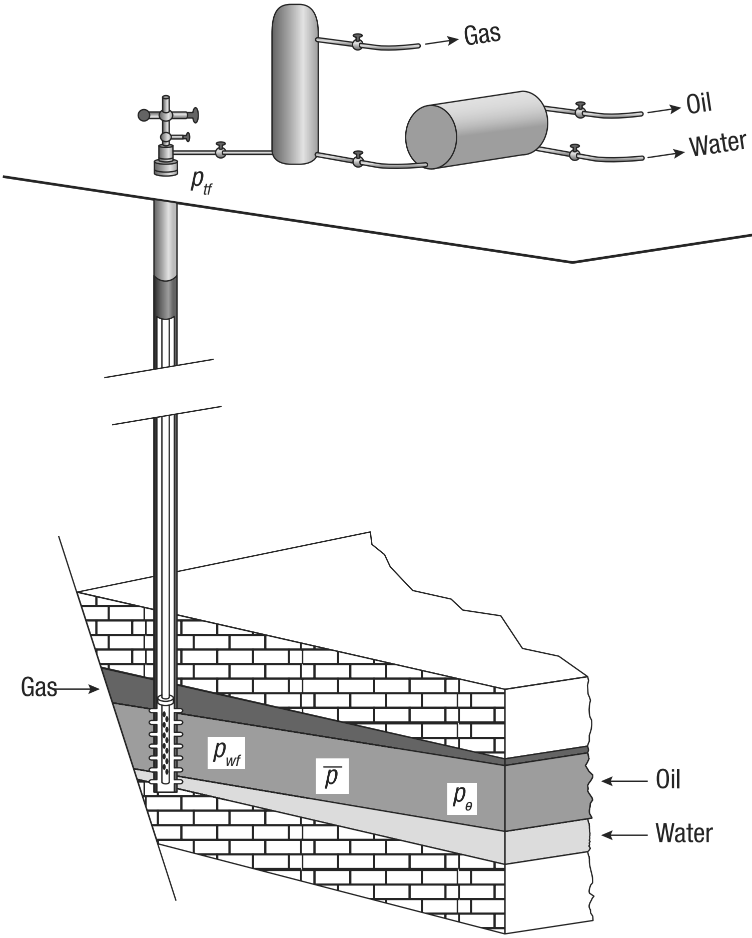

Figure 1-6 The petroleum production system, including the reservoir, underground well completion, the well, wellhead assembly, and surface facilities.

Equation (1-6) succinctly describes what is possible for a petroleum production engineer. First, the dimensioned productivity index with units of flow rate divided by pressure is proportional to the dimensionless (normalized) productivity index J_D. The latter, in turn, has very well-known representations. For steady-state flow to a vertical well,

$$J_D = \frac{1}{\ln\left(\frac{r_e}{r_w}\right) + s}. \tag{1-7}$$

For pseudosteady state flow,

$$J_D = \frac{1}{\ln\left(\frac{r_e}{r_w}\right) - 0.75 + s}, \tag{1-8}$$

and for transient flow,

$$J_D = \frac{1}{p_D + s} \tag{1-9}$$

where p_D is the dimensionless pressure. The terms steady state, pseudosteady state, and transient will be explained in Chapter 2. The concept of the dimensionless productivity index combines flow geometry and skin effects, and can be calculated for any well by measuring flow rate and pressure (reservoir and flowing bottomhole) and some other basic but important reservoir and fluid data.

For a specific reservoir with permeability k, thickness h, and with fluid formation volume factor B and viscosity μ, the only variable on the right-hand side of Equation (1-6) that can be engineered is the dimensionless productivity index. For example, the skin effect can be reduced or eliminated through matrix stimulation if it is caused by damage or can be otherwise remedied if it is caused by mechanical means. A negative skin effect can be imposed if a successful hydraulic fracture is created. Thus, stimulation can improve the productivity index. Finally, more favorable well geometry such as horizontal or complex wells can result in much higher values of J_D.

In reservoirs with pressure drawdown-related problems (fines production, water or gas coning), increasing the productivity can allow lower drawdown with economically attractive production rates, as can be easily surmised by Equation (1-6).

Increasing the drawdown $(p - p_{wf})$ by lowering p_{wf} is the other option available to the production engineer to increase well deliverability. While the IPR remains the same, reduction of the flowing bottomhole pressure would increase the pressure gradient $(p - p_{wf})$ and the flow rate, q, must increase accordingly. The VFP change in Figure 1-7 shows that the flowing bottomhole pressure may be lowered by minimizing the pressure losses between the bottomhole and the separation facility (by, for example, removing unnecessary restrictions, optimizing tubing size, etc.), or by implementing or improving artificial lift procedures. Improving well deliverability by optimizing the flow system from the bottomhole location to the surface production facility is a major role of the production engineer.

In summary, well performance *evaluation* and *enhancement* are the primary charges of the production engineer. The production engineer has three major tools for well performance evaluation: (1) the measurement of (or sometimes, simply the understanding of) the

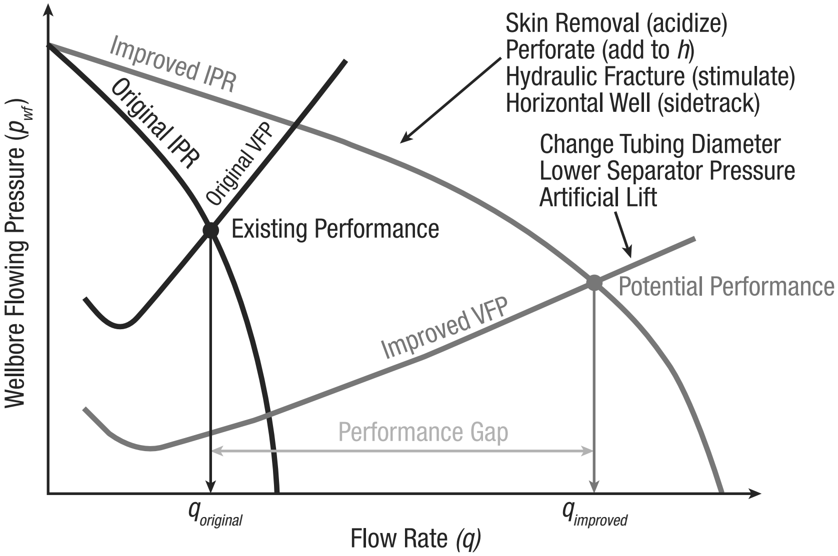

Figure 1-7 Well deliverability gap between the original well performance and optimized well performance.

rate-versus-pressure drop relationships for the flow paths from the reservoir to the separator; (2) well testing, which evaluates the reservoir potential for flow and, through measurement of the skin effect, provides information about flow restrictions in the near-wellbore environmental; and (3) production logging measurements or measurements of pressure, temperature, or other properties by permanently installed downhole instruments, which can describe the distribution of flow into the wellbore, as well as diagnose other completion-related problems.

With diagnostic information in hand, the production engineer can then focus on the part or parts of the flow system that may be optimized to enhance productivity. Remedial steps can range from well stimulation procedures such as hydraulic fracturing that enhance flow in the reservoir to the resizing of surface flow lines to increase productivity. This textbook is aimed at providing the information a production engineer needs to perform these tasks of well performance evaluation and enhancement.

1.3.2 Organization of the Book

This textbook offers a structured approach toward the goal defined above. Chapters 2–4 present the inflow performance for oil, two-phase, and gas reservoirs. Chapter 5 deals with complex well architecture such as horizontal and multilateral wells, reflecting the enormous growth of this area of production engineering since the first edition of the book. Chapter 6 deals with the condition of the near-wellbore zone, such as damage, perforations, and gravel packing. Chapter 7 covers the flow of fluids to the surface. Chapter 8 describes the surface flow system, flow in horizontal pipes, and flow in horizontal wells. Combination of inflow performance and well performance versus time, taking into account single-well transient flow and material balance, is shown in Chapters 9 and 10. Therefore, Chapters 1–10 describe the workings of the reservoir and well systems.

Gas lift is outlined in Chapter 11, and mechanical lift in Chapter 12.

For an appropriate product engineering remedy, it is essential that well and reservoir diagnosis be done.

Chapter 13 presents the state-of-the-art in modern diagnosis that includes well testing, production logging, and well monitoring with permanent downhole instruments.

From the well diagnosis it can be concluded whether the well is in need of matrix stimulation, hydraulic fracturing, artificial lift, combinations of the above, or none.

Matrix stimulation for all major types of reservoirs is presented in Chapters 14, 15, and 16. Hydraulic fracturing is discussed in Chapters 17 and 18.

Chapter 19 is a new chapter dealing with advances in sand management.

This textbook is designed for a two-semester, three-contact-hour-per-week sequence of petroleum engineering courses, or a similar training exposure.

To simplify the presentation of realistic examples, data for three characteristic reservoir types—an undersaturated oil reservoir, a saturated oil reservoir, and a gas reservoir—are presented in Appendixes. These data sets are used throughout the book. Examples and homework follow a more modern format than those used in the first edition. Less emphasis is given to hand-done calculations, although we still think it is essential for the reader to understand the salient fundamentals. Instead, exercises require application of modern software such as Excel spreadsheets and the PPS software included with this book, and trends of solutions and parametric studies are preferred in addition to single calculations with a given set of variables.

1.4 Units and Conversions

We have used “oilfield” units throughout the text, even though this system of units is inherently inconsistent. We chose this system because more petroleum engineers “think” in bbl/day and psi than in terms of m^3/s and Pa. All equations presented include the constant or constants needed with oilfield units. To employ these equations with SI units, it will be easiest to first convert the SI units to oilfield units, calculate the desired results in oilfield units, then convert the results to SI units. However, if an equation is to be used repeatedly with the input known in SI units, it will be more convenient to convert the constant or constants in the equation of interest. Conversion factors between oilfield and SI units are given in Table 1-1.

Table 1-1 Typical Units for Reservoir and Production Engineering Calculations

Variable	Oilfield Unit	SI Unit	Conversion (Multiply SI Unit)
Area	acre	m^2	2.475×10^{-4}
Compressibility	psi^{-1}	Pa^{-1}	6897
Length	ft	m	3.28
Permeability	md	m^2	1.01×10^{15}
Pressure	psi	Pa	1.45×10^{-4}
Rate (oil)	STB/d	m^3/s	5.434×10^5
Rate (gas)	MSCF/d	m^3/s	3049
Viscosity	cp	Pa-s	1000

Example 1-1 Conversion from Oilfield to SI Units

The steady-state, radial flow form of Darcy's law in oilfield units is given in Chapter 2 as

$$p_e - p_{wf} = \frac{141.2 qB\mu}{kh}\left(\ln\frac{r_e}{r_w} + s\right) \tag{1-10}$$

for p in psi, q in STB/d, B in res bbl/STB, μ in cp, k in md, h in ft, and r_e and r_w in ft (s is dimensionless). Calculate the pressure drawdown $(p_e - p_{wf})$ in Pa for the following SI data, first by converting units to oilfield units and converting the result to SI units, then by deriving the constant in this equation for SI units.

Data

$q = 0.001\ \mathrm{m^3/s}$, $B = 1.1$ res $\mathrm{m^3/ST\ m^3}$, $\mu = 2 \times 10^{-3}$ Pa-s, $k = 10^{-14}\ \mathrm{m^2}$, $h = 10$ m, $r_e = 575$ m, $r_w = 0.1$ m, and $s = 0$.

Solution

Using the first approach, we first convert all data to oilfield units. Using the conversion factors in Table 1-1,

$$q = \left(0.001\frac{\mathrm{m}^3}{\mathrm{s}}\right)(5.434 \times 10^5) = 543.4\ \mathrm{STB/d} \tag{1-11}$$

$$B = 1.1\ \text{res bbl/STB} \tag{1-12}$$

$$\mu = (2 \times 10^{-3}\ \text{Pa-s})(10^3) = 2\ \text{cp} \tag{1-13}$$

$$k = (10^{-14}\ \mathrm{m}^2)(1.01 \times 10^{15}) = 10.1\ \text{md} \tag{1-14}$$

$$h = (10\ \mathrm{m})(3.28) = 32.8\ \text{ft.} \tag{1-15}$$

Since r_e is divided by r_w, the units for these radii do not have to be converted. Now, from Equation (1-10),

$$p_e - p_{wf} = \frac{(141.2)(543.4)(1.1)(2)}{(10.1)(32.8)}\left[\ln\left(\frac{575}{0.1}\right) + 0\right] = 4411\ \text{psi} \tag{1-16}$$

and converting this results to Pascals,

$$p_e - p_{wf} = (4411\ \text{psi})(6.9 \times 10^3) = 3.043 \times 10^7\ \text{Pa} \tag{1-17}$$

Alternatively, we can convert the constant 141.2 to the appropriate constant for SI units, as follows (including only-to-be-converted variables):

$$p_e - p_{wf}(\text{Pa}) = \frac{(141.2)[q(\mathrm{m}^3/s)(5.43 \times 10^5)][\mu(Pa - s)(10^3)]}{[k(\mathrm{m}^2)(1.01 \times 10^{15})][h(\mathrm{m})(3.28)]}(6.9 \times 10^3) \tag{1-18}$$

or

$$p_e - p_{wf} = \frac{0.159qB\mu}{kh}\left(\ln\frac{r_e}{r_w} + s\right) = \frac{qB\mu}{2\pi kh}\left(\ln\frac{r_e}{r_w} + s\right). \tag{1-19}$$

The constant derived, 0.159, is $1/2\pi$, as it should be for this consistent set of units. Substituting the parameters in SI units directly into Equation (1-19), we again calculate that $p_e - p_{wf} = 3.043 \times 10^7$ Pa.

Often, in regions where metric units are customary, a mix of SI and non-SI units is sometimes employed. For example, in using Darcy's law, the units for flow rate may be m^3/d; for viscosity, cp; for permeability, md; and so on. In this instance, units can be converted to oilfield units in the same manner demonstrated here for consistent SI units.

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Index

Note: Page numbers with "f" indicate figures; those with "t" indicate tables.

A

ACA (after-closure analysis), 430, 433, 434–35
Acid
  acid/rock interactions (*See* Matrix acidizing)
  additives, in sandstone acidizing design, 512
  concentration profiles, 475f
  gas, 68
  injection into gas reservoir, 494–96
  placement, mechanical, 496–97
  reaction products, precipitation of, 461–64
  response curves, 471f
  selection, in sandstone acidizing design, 470–71, 471t
  transport to mineral surface, 460–61
Acid capacity number
  fast-reacting minerals, 474, 477
  HCI, 510
  slow-reacting minerals, 474
Acid fracture conductivity, 545–52
  average, 551, 552t
  effective, 548–49t
  fracture width profile along a fracture, 546f
Acid fracturing, 541–54
  acid diffusion coefficients, 544f
  acid fracture conductivity, 545–52
  acid-fractured well, productivity of, 552–53, 553f
  acid penetration distance, 544–45
  acid penetration in fractures, 542–45, 543f
  vs. matrix acidizing, 443
  propped fracture *vs.* acid fracture performance, 553–54
  well productivity, 552–53, 553f
Acidizing process, optimal rate schedule for monitoring, 486–96
  acid injection into gas reservoir, 494–96
  acid treatment data, 492t
  design chart for monitoring acidizing, Paccaloni's, 489–90, 490f
  injection rate and pressure, maximum, 487–89, 488f
  maximum Δp, maximum rate procedure, Paccaloni's, 489–90, 490f
  skin factor evolution during acidizing, 486f, 490–93, 493t, 494f
Acidizing treatment. *See also* Matrix acidizing
  in sandstone acidizing design, 512–13
Acid-mineral reaction kinetics, 453–60
  constants in HCI-mineral reaction kinetics models, 455t
  constants in HF-mineral reaction kinetics models, 456t
  dissolution rate of rotating disk of feldspar, 457–58
  fluosilicic acid with sandstone minerals, 460
  HCl and weak acids with carbonates, 454–55
  HF with sandstone minerals, 455–60
  measurement of, 454
  relative reaction rates of sandstone minerals, 459
Acid-mineral reaction stoichiometry, 446–52
  chemical reactions, primary, 448t
  dissolving power of acids, 450t, 451t
  HCI preflush volume, calculating, 452
  spending of acid components, 451t
Acid penetration
  distance, 544–45
  in fractures, 542–45, 543f
Acid volume, 472–96
  acidizing process, optimal rate schedule for monitoring, 486–96
  design, 478–80
  injection rate and, 472–96
  to remove drilling mud damage, 480–81, 481f
  sandstone acidizing models, 472–85
  treatment design, competing factors influencing, 472
After-closure analysis (ACA), 430, 433, 434–35
Agarwal-Gardner type curves, 578–79, 578f
Altered permeability, 8

Altered porosity, 8
Anisotropy, 2, 3f, 401
  dependence of deviated well skin factor on reservoir, 134
  horizontal, 113
  ratio, 98, 104
  vertical-to-horizontal, 95, 97–98, 112
Annular flow, 179, 188, 220, 221, 221f, 222, 223f, 224f, 226
Annular mist flow, 222, 223f, 224f, 226
Areal extent, 7–8
Arps decline curve analysis, 388, 388t, 390
Artificial lift, 11, 13

B

Babu-Odeh model, 103–9
  schematic of, 103f
  well performance with, 106–8
Backflow, 392
Baker flow regime map, 222f, 225–26
Ball sealers, 497
Barnett shale formation, 586
Beam loads, sucker rod and, 345–47
Beam pumping units, 345
Bean (choke diameter), 241
Before-closure behavior, 430, 432, 433, 435–37
Beggs-Brill correlation, 201–6, 223, 226–28
Beggs-Brill flow regime map, 224f, 225, 226
B factor correlations, 693t
Bilinear flow, 416, 416f, 418–20
Biological damage, 157
Biwing fracture, events with, 648f
Borate-crosslinked fluid, properties of, 638–39f, 638–40
Bottomhole flowing pressure, 1, 4, 6, 10–11, 13
  in gas well, calculating, 182–84
  in gas well, flow rate *vs.,* 78–79, 78t, 79f
  with GLR values of 300 and 800 SCF/STB, 264–65
  injected gas, 313
  injection rate increase, impact of, 312–13
  modified Hagedorn-Brown correlation, 266, 266t
  production rates, 266, 266t
  reduction in, VFP curve and, 268
  well deliverability, 261
  wellhead pressure, 262
Bottomwater, excessive, 380–81
Boundaries, 2, 3f
Boundary dominated flow, 577
Breakdown pressure, 602, 604, 605, 605f, 606f
Brill-Mukherjee model, 192
Bubble flow, 188, 210
  dispersed, 222, 222f, 223f, 224f, 226
  elongated, 222, 222f, 223f, 224f
  Griffith correlation, 198–201
Bubble-point pressure, 6
  introduction, 41–42
  PVT properties below, 43, 45f
  saturated oil characterized by, 42–43
Buijse-Glasbergen model, 529–31, 531f
Buildup analysis. *See also* Log-log diagnostic plot
  limited-entry vertical well, 413–14, 414f
  for limited-entry well, 413–14, 414f
  model match for, 409f, 414f

C

Cake resistance, effect on acid placement, 506–8
  injection rate history, total, 508f
  injection rate into high-permeability layer, 507f
  injection rate into low-permeability layer, 507f
Carbonate acidizing design, 519–55
  acid fracturing, 541–54
  HCl acid and weak acid reactions with, 454–55
  horizontal wells, acidizing of, 554–55, 554f
  introduction, 519–22
  matrix acidizing design for carbonates, 535–41
  skin evolution during, 539–40, 540f
  wormhole formation and growth, 522–25
  wormhole propagation models, 525–35
Cased hole logs, 368–87. *See also* Production log evaluation
Cased well, 9–10, 10f
  completion skin factors, 138–46
Cavity completion, 677
Cemented well, 9–10, 10f
Cement evaluation, 368–69, 369f
Cement squeeze, 370, 374–75
Channeling, 374–375f, 374–76, 376f
Chemical precipitation, 154–55
Chen equation, 177–78, 197, 206
Choke, 236–47
  critical flow, 242, 246, 247
  diameter (bean), 241
  flow coefficient, 240f
  flow rate, 237

  gas-liquid flow, 243–47
  horizontal well flow profile, 255f
  kinetic energy pressure drop through, 240
  performance curves, 246–47, 247f
  schematic of, 237f
  single-phase gas flow, 241–43
  single-phase liquid flow, 240–41
  size, 242, 243f, 244–46, 255f
  transverse hydraulic fractures, 592–94
Churn flow, 188, 191
Closure stress, 430–37
  after-closure analysis, 430, 433, 434–35
  before-closure behavior, 430, 432, 433, 435–37
  vs. proppant conductivity, 643, 644f
Colebrook-White equation, 176–77
Completion damage, 159–61
Completion failure avoidance, 698–99
Complex fracture geometry, creating, 615–16
Complex fracturing, defined, 610, 615
Compressible, single-phase flow of, 179–84
  calculation of bottomhole flowing pressure in gas well, 182–84
  equation for pressure drop, 179–82
Condensate, 7
Conductive fracture length, 562–66, 565f
Conductivity performance
  finite fracture, 578–79
  infinite fracture, 574–78
Conical wormhole forms, 523
Connate water saturation, 4
Continuous gas-lift design, 303–10
  gas compressors, power requirements for, 309–10
  GLR and gas-lift rate, calculating, 303–4
  natural *vs.* artificial flowing gradient, 303–4
  point of injected gas, 305–8
  pressure of injected gas, 304–5
  tubing performance curve, 306, 308f
Continuous gas-lift system, 300–301, 301f
Correlations
  Beggs-Brill, 201–6, 223, 226–28
  β factor, 693t
  Dukler, 231–34
  Eaton, 228–31
  empirical constants in two-phase critical flow, 243–44, 244t
  flow in formation in non-Darcy coefficient, 81–82t
  Gilbert, 243, 244–46, 244t
  Gray, 206–10
  Griffith, 198–201
  Hagedorn-Brown, 192–98, 228
  Omana, 244, 245, 246
  porosity *vs.* permeability, 8
  pressure gradient, 226, 230, 231, 232
  property, for two-phase systems, 47–52
  Ros, 243, 244–46, 244t
  two-phase, for horizontal well inflow, 115–16
Cricondentherm, 7
Critical depth for horizontal fracture, 607–8, 608f
Critical flow
  vs. critical point of fluid, 237
  empirical correlations for, in gas-liquid flow, 243–44, 244t
  through choke, 242, 246, 247
Critical point, 6
Crossover method of gravel pack placement, 680, 681f
Cylindrical flow, 401, 418

D

Damkohler number, 474–75
Darcy. *See also* Non-Darcy flow
  experiment, 8–9, 9f
  law in radial coordinates, 19
Data farcs, 303
Decline curve analysis, 387–90, 590, 591f
Δ in kinetic energy pressure drop, meaning of, 234
Δp_{F}, frictional pressure drop, 176–79
Δp_{KE}, pressure drop due to kinetic energy change, 174–76
Δp_{PE}, pressure drop due to potential energy change, 173–74
Depth
  critical, for horizontal fracture, 607–8, 608f
  stresses *vs.,* 604
Design fracture treatment to achieve optimal dimensions, 634–35
Deterministic models, 192
Deviated production wells in HPF, 694–97, 698f
Dew-point curve, 7
Diagnostic fracture injection test (DFIT). *See* Fracture calibration injection falloff
Differential depletion, 392, 393
Dimensionless effective wellbore radius, 563, 564, 564f

Dimensionless groups in sandstone acidizing model, 476t
Dimensionless productivity index, 13
Discontinuities, 2, 3f
Dispersed bubble flow, 222, 222f, 223f, 224f, 226
Distributed flow, 220–26
  bubble, 221f, 222, 222f, 223f, 224f, 226
  mist, 221f, 222, 222f
Downhole instruments, 14
Downhole properties, estimating, 51–52
Draining patterns, irregular, 30–34
  production rate and, 30, 32
  reservoir pressure in adjoining drainage areas, determining, 32–34, 32f
  shape factor for closed, single-well drainage areas, 31f
Drawdown, 13, 16, 22
Drawdown failure condition, 666–67, 671f
Drilling damage
  mud, acid volume needed to remove, 480–81, 481f
  sources of, 157–59
Dual-porosity approach, 592
Dukler correlation, 231–34, 233f
Duns-Ros flow regime map, 188, 190f
Dynamic displacement pumps, 335, 354–59
  electrical submersible, 354–59
Dynamic value, 610
Dynamometer card
  for elastic rods, 348f
  from properly working rod pump, 348f
  rod pump performance analyzed from, 347–50
  shapes, 348–50, 349f

E

Eaton correlation, 228–31
  friction factor, 228, 229f
  holdup, 228, 229f
Economides et al. model, 109–13
  parallelepiped model with appropriate coordinates, 110f
  results summary, 113t
  shape factors, approximate, 111t
  well performance with, 112–13
Effective drainage radius, 80, 390, 418
Effective wellbore radius, 21–22
Electrical resistivity, 5–6, 5f
Electrical submersible pump (ESP), 335, 354–59
  completion, 353f, 354, 355f
  design, 357, 358–59
  pump characteristic chart, 354, 356f, 358f
  selecting, 356–57
Ellipsoidal flow around perforation, 476f
Elongated bubble flow, 222, 222f, 223f, 224f
Empirical models, 192
Emulsions, fluid damage and, 155–56
Equations
  Chen, 177–78, 197, 206
  Colebrook-White, 176–77
  flow regimes, 402–3t
  Hagen-Poiseuille, 171, 172
  mechanical energy balance, 172, 179, 192, 193–94, 335
  pressure drawdown, 25
  pressure drop, 179–82
ESP. *See* Electrical submersible pump (ESP)
EUR (expected ultimate recovery), 388–90, 389f
Expected ultimate recovery (EUR), 388–90, 389f
Exponential decline, 577

F

Fanning friction factor, 176, 197, 210
Feldspar, dissolution rate of rotating disk of, 457–58
Fetkovich's approximation, 57–58
F-function constants, 573, 573t
Fine migration, mechanisms for, 154
Fines, 151
Finite fracture conductivity performance, 578–79
Fittings, equivalent lengths of, 238–39t
Flow, 217–56
  capacity of low-pressure gas line, 219–20
  horizontal pipes, 217–36
  horizontal wellbores, 250–56
  introduction, 217
  surface gathering systems, 247–50
  through chokes, 236–47
Flow geometries. *See* Flow regimes
Flow profile used to evaluate damaged well, 372
Flow regime analysis, 400–437
  flow regime equations, 402–3t
  fracture calibration injection falloff, 429–37, 430, 431f
  horizontal well, 429, 429f
  limited-entry vertical well, 410–16, 410f
  permeability, determining, 401
  pressure buildup analysis, 406–7, 410f
  radial flow geometries for vertical wells, 405

  reservoir pressure, estimating, 405–6
  skin factor, estimating, 405
  transient well analysis, 400–437
  unit conversion factors, 404t
  vertically fractured vertical well, 416–28
  wellbore storage, 407–10
Flow regime maps, 188, 190–91
  Baker, 222f, 225–26
  Beggs-Brill, 224f, 225, 226
  Duns-Ros, 188, 190f
  Mandhane, 223, 223f, 225, 226
  Taitel-Dukler, 190–91, 190f, 223, 224f
Flow regimes. *See also* Single-phase flow regimes; Two-phase flow regimes
  defined, 400–401
  distributed, 220, 221f, 222, 223, 224f
  equations, 402–3t
  intermittent, 220, 221f, 222, 223, 224f, 226, 227
  limited-entry vertical well, 410–11, 410f
  maps of (*See* Flow regime maps)
  pressure buildup analysis, 406–7, 410f
  segregated, 220–21, 221f, 223, 224f
  vertically fractured vertical well, 416–19, 416f
Fluid damage, 155–56
Fluid diversion in carbonates, 540–41
Fluid efficiency in fracture calibration injection falloff, 430, 432, 433t, 435
Fluid placement and diversion, 496–509
  ball sealers, 497
  mechanical acid placement, 496–97
  particulate diverting agents, 497–508
  viscous diversion, 508–9
Fluid saturations, 4–6
Fluid volume
  calculations, total, 626–28
  requirements, 624–29
Fluosilicic acid reactions with sandstone minerals, 460
Formation damage, 157–63
  completion damage, 159–61
  drilling damage, 157–59
  injection damage, 162–63
  production damage, 161–62
  during well operations, sources of, 157–63
Formation damage mechanisms, 151–57
  biological damage, 157
  chemical precipitation, 154–55
  emulsions, 155–56
  fine migration, mechanisms for, 154
  mechanical damage, 156
  particle plugging of pore spaces, 151–54
  permeability, 155–56
  wettability changes, 155–56
Formation flow velocity
  in gravel pack completion, 687–88
  to HPF, 693–94
Formation fluid sampling, 391–93
Formation linear flow, 416
Formation linear flow approximation, 577–78
Formation sand production, factors affecting, 662–72
  drawdown failure condition, 666–67, 671f
  events to induce sand problems, 663f
  Mohr circle, 663, 663f
  Mohr-Coulomb criterion, 664–65, 664f, 666f
  numerical simulation cases, conditions for, 667–69, 668t, 669f
  productivity ratio *vs.* perforation density, 672f
  shut-in, 669–70
  simulated failure criteria, 670f
Frac-pack completion, 688–93
  β factor correlations for, 693t
  flowing perforations, number of, 692
  model for radial and fracture-face damage, 689–90, 690f
  skin, 690–91
Fracture calibration injection falloff, 429–37, 430, 431f
  closure stress, 430–37
  fluid efficiency, 430, 432, 433t, 435
  fracture height, 432, 433t, 436
  fracture models, 432, 433t, 434
  fracture width, 432, 433t, 436
  g-function, 430
  leakoff coefficient, 430, 432, 433t, 435
  log-log diagnostic plot, 430, 431f
  parameters, 430
  power law fracture surface growth assumption, 430, 432
  sequence of events observed in, 430, 431f
Fracture diagnostics, 646–50
  fracture geometry measurement, 647–50
  fracturing pressure analysis, 646–47
  Nolte-Smith analysis pressure response modes, 647t
  Nolte-Smith plot, 646–47, 647f
Fracture direction in reservoir rock, 606–7, 608–9
Fractured oil well model match, 422f

Fractured well behavior in low-permeability reservoirs, 574–79
  Agarwal-Gardner type curves, 578–79, 578f
  finite fracture conductivity performance, 578–79
  formation linear flow approximation, 577–78
  infinite fracture conductivity performance, 574–78
  long-term, 575–76, 577f
Fractured well performance, 585–92
  shale reservoirs, 586–92
  tight gas reservoirs, 586
Fractured well productivity, 566–73
Fracture geometry, 609–16. *See also* Fracture width
  complex, creating, 615–16
  evolving, 628–29, 629f
  measurement, 647–50
  TSO treatments, 615
Fracture geometry and net pressure, 616–35
  design fracture treatment to achieve optimal dimensions, 634–35
  fluid volume calculations, total, 626–28
  fluid volume requirements, 624–29
  height migration, 621–23, 622f, 624f
  net fracturing pressure, 616–20, 621
  pad volume calculations, total, 626–28
  proppant schedule, 629–30, 631f
  propped fracture width, 631–35
Fracture geometry for maximizing fractured well productivity, 566–73, 568f, 569f, 570f
  calculating, 571–72
  F-function constants, 573, 573t
  unified fracture design, 567–73
Fracture geometry measurement, 647–50
  microseismic monitoring, 648–50
  tiltmeter mapping, 650
  tracers and temperature, 650
Fracture height
  fracture calibration injection falloff, 432, 433t, 436
  mapping, with microseismic monitoring, 650f
  measured with radioactively tagged proppant, 382–83, 384f
  migration, 621–23, 622f, 624f
  production log evaluation, measurement of, 381
  temperature log interpretation of, in production log evaluation, 382, 383f
Fracture initiation pressure, calculating, 606
Fracture injection tests, 603
Fracture length, 562–66, 565f
Fracture models
  KGD, 432, 433t
  PKN, 433t, 434
  radial, 432, 433t
Fracture patterns, 586–89, 588f, 589f
  drainage, 589f
  microseismic map of, 589f
  in tight reservoirs, 586, 588, 588f
Fracture ports, 653
Fracture properties in HPF, 697t
Fractures. *See* Acid fracturing
Fracture width
  fracture calibration injection falloff, 432, 433t, 436
  KGD model, 609–10, 614, 614f
  non-Newtonian fluid, 610, 613
  PKN model, 609, 610–13, 611f
  radial model, 609, 615
Fracturing. *See* Acid fracturing; Hydraulic fracturing for well stimulation
Fracturing fluids, 635–42
  frictional pressure drop during pumping, 641–42
  perfect, 646
  rheological properties, 636–41
  selection guide, 637f
  usage, 635f
Fracturing horizontal wells, 651–55
  fracture orientation in, 651–52, 651f
  well completions for multiple fracturing, 652
Fracturing pressure analysis, 646–47
Frictional pressure drop
  Δp_F, 176–79
  during pumping, 641–42
  well length, 11
Friction factor correlation, Eaton, 228, 229f
Froth flow, 222, 223f, 224f, 226
Froude number, 223, 224f, 226
Full-strength mud acid, 470
Furui et al. model, 100–103
  schematic of, 101f
  well performance with, 102–3
  wormhole, 531–35, 534f

G

Gas
  effect on pump efficiency, 350–52, 350f
  in reservoir fluid, 11
  use of term, 4
Gas anchors, 352
Gas compressibility factor
  calculated, in transient IPR for gas well, 88–90t
  correction for nonhydrocarbon gases, 68–71
  for mixtures of hydrocarbon gases, 63–65, 64f
  of sour gas, 70–71, 70t
Gas compressors, power requirements for, 309–10
Gas coning, 379–80, 380f
Gas deviation factor. *See* Gas compressibility factor
Gas flow, 218–20, 241–43. *See also* Gas-liquid flow
  capacity of low-pressure gas line, 219–20
  excessive, 374, 378–79, 378f, 379f
  kinetic energy pressure drop in, 218
  performance for different choke sizes, 242, 243f
  preferential, 376–77
  single-phase, 218–20, 241–43
Gas formation volume factor, 7–8, 74–75
Gas gravity, 61–63
  pseudocritical properties from, 66–68
Gas isothermal compressibility, 75–76
Gas lift, 11, 299–332
  depleting reservoir, 330, 330f
  economics of, 324–26, 325f, 325t
  introduction, 299
  near-wellbore damage and, 232f, 321, 322–24
  onset of, 331–32
  performance, GLR and, 261–62
  purpose of, 261
  requirements *vs.* time, 328–32
  tubing size *vs.* gas-lift requirements, 326–27, 327f, 328f, 329f
  types of, 300–301, 301f
  valves, unloading wells with multiple, 310–12
Gas-lift design
  continuous, 303–12
  optimization of, 312–16
Gas-lift design, continuous, 303–12
  flowing gradient, natural *vs.* artificial, 303–4
  gas compressors, power requirements of, 309–10
Gas-lift design, optimization of, 312–16
  GLR values, 312–15, 315f, 316f, 318f, 319f
  injection rate increase, impact of, 312–13
  maximum production rate with gas lift, 314–16, 315f, 316f
  sustaining production rate while pressure depletes, 313–14
Gas-lift performance curve, 316–28, 321f
  development of, 319–20
  IPR and optimum gas lift, 321f
  time dependency, 320f
Gas-lift system, 299–302. *See also* Gas-lift valves
  completions of, 299, 300, 301f
  schematic of, 300f
Gas-lift valves, 300–301, 302f
  multiple, unloading wells with, 310–12, 311f
  opening and closing, 301
  positioning, 300
  pressure regulator, 301, 302f
Gas-liquid flow, 243–47
  choke size for, 244–46
  horizontal, predicting, 225–26
  through chokes, 243–47
Gas-liquid ratio (GLR)
  continuous gas-lift design, 303–4
  gas lift performance, 261–62
  gradient curves for, 303
  gradient curves for range of values, 265f
  liquid production rate *vs.,* 319f, 320f
  maximum gas-lift production rate, 312–15, 315f, 316f, 318f
  optimum gas-lift performance, 317–21, 317f
  VFP and, impact on, 264–65
Gas production gathering systems. *See* Surface gathering systems
Gas viscosity, 71–74, 72–73f
Gas well
  acid injection into, 494–96
  horizontal, inflow performance relationship for, 114–15
  material balance, 294–96
  performance and production forecast, 294–96, 296t
  transient flow of, 84–91
Gas well deliverability, 270–73, 272f
  approximation of, 76–79
  curve, formation of, 82–83, 84f
  flow rate *vs.* bottomhole pressure for gas well, 78–79, 78t, 79f
  IPR and VFP in, 270–73, 272f
  for non-Darcy flow, 79–84, 84f
  tubing size and, 272–73, 273f

Gel frac *vs.* Waterfrac map, comparison of, 649f
Generalized expression, 281–82
G-function, 430
Gilbert correlation, 243, 244–46, 244t
GLR. *See* Gas-liquid ratio (GLR)
Gradient curves, 213, 213f
  expanded-scale, 332f
  in gas-lift requirements *vs.* time, 329f
  for GLR, 265f, 303
  intersection of gas injection pressure with, 309f, 310
  in tubing size *vs.* gas-lift requirements, 326–27, 327f, 328f
Gravel pack completion, 678–88
  β factor correlations for, 693t
  formation flow velocity, 687–88
  gravel and screen sizing, 682–86, 683–84t
  gravel pack evaluation, 688
  high-rate water pack, 686–88
  log showing response to voids in gravel pack, 689f
  productivity of gravel-packed wells, 686
  skin factors, 148–51
  types, 678, 679f
Gravel packing, 10, 10f
Gravel pack placement, 678–80
  crossover method of, 680, 681f
  for inside-casing gravel packs, 680, 681f
  in open-hole or underreamed casing completions, 679, 680f
Gravel sizing, 682–86, 683–84t
Gray correlation, 206–10
Griffith correlation, 198–201
Gross height, 4

H

Hagedorn-Brown correlation, 228
  modified (mH-B), 192–93, 266, 266t
  original, 193–98
Hagen-Poiseuille equation for laminar flow in pipe, 171, 172
Halo, 688
Hawkins' formula, 122–26
HCI. *See* Hydrochloric (HCl) acid
Height. *See* Fracture height
Height migration, 621–23, 622f, 624f
Heterogeneities, 2, 3f. *See also* Acid-mineral reaction kinetics
HF. *See* Hydrofluoric (HF) acid
High-conductivity vertically fractured vertical well, production data analysis for, 420–24, 423f
High-performance fracturing (HPF), 693–97
  in deviated production wells, 694–97, 698f
  flow directly to abandoned perforations, 696f
  formation flow velocity to, 693–94
  perforating strategy for, 697–98
  reservoir and fracture properties, 697t
High-permeability layers
  excessive flow through, 378–79, 378f, 379f
  preferential flow through, 376–77
High-permeability reservoirs, 560f
High-rate horizontal well, pressure drop in, 252–54
High-rate water pack, 686–88
Holdup behavior, 185–87
Holdup phenomenon, 185–87
Horizontal anisotropy, 113
Horizontal borehole, measurements along, 393, 393f
Horizontal gas wells, inflow performance relationship for, 114–15
Horizontal permeability, 401
Horizontal pipes, flow in, 217–36
  Beggs-Brill correlation, 226–28
  Dukler correlation, 231–34
  Eaton correlation, 228–31
  flow regimes, 220–26, 221f
  gas, single-phase flow, 218–20
  liquid, single-phase flow, 217–18
  pressure gradient correlations, 226
  pressure traverse, calculating, 234–36
  two-phase flow, 220–36
  wellbore pressure drop for, 252–56
Horizontal well
  acidizing, 554–55, 554f
  damage skin effect, 134–37
  drainage pattern formed around, 96f
  gas, inflow performance relationship for, 114–15
  inflow, two-phase correlations for, 115–16
  introduction, 95–97
  multilateral well technology, 116–17, 117f
  perforation skin factor for, 145–46
  production from, 95–117
  productivity index for, *vs.* vertical wells, 108–9

  pseudosteady state flow, 103–13
  steady-state well performance, 97–103
Horizontal wellbores, flow in, 250–56. *See also* Pressure drop
HPF. *See* High-performance fracturing (HPF)
Hydraulic fracture, 9
  defined, 559
  diagram of, 560f
  tubing size selection in gas well, 272–73
Hydraulic fracturing for well stimulation, 559–94
  choke effect for transverse hydraulic fractures, 592–94
  conductive fracture length, 562–66, 565f
  effective wellbore radius, 564f
  fractured well behavior, 574–79
  fractured well performance, 585–92
  fracture geometry for maximizing fractured well productivity, 566–73, 568f, 569f, 570f
  fracture length, 562–66, 565f
  fracture patterns, 586–89, 588f, 589f
  high-permeability reservoirs, production and recovery acceleration, 560f
  introduction, 559–62
  low-permeability reservoirs, 561f, 574–79
  non-Darcy flow, 579–85
  shale reservoirs, fractured well performance for, 586–92
  skin effect, 562–66, 565f
  SRV, 562f, 588
  tight gas reservoirs, fractured well performance for, 586, 588f
Hydraulic fracturing treatments, design and execution of, 601–55
  fracture diagnostics, 646–50
  fracture geometry, 609–16
  fracture geometry and net pressure, created, 616–35
  fracturing fluids, 635–42
  fracturing horizontal wells, 651–55
  introduction, 601–2
  proppants and fracture conductivity, 642–46
  proppant schedule, 629–30, 631f
  reservoir rock, fracturing of, 602–9
Hydrocarbon mixture, schematic phase diagram of, 42f
Hydrocarbons, 4
Hydrocarbon saturation, 5
Hydrochloric (HCl) acid
  acid capacity number for, 510
  constants in HCI-mineral reaction kinetics models, 455t
  effective diffusion coefficient of, 460, 461f
  preflush, 509–11
  preflush volume, calculating, 452
  weak acid reactions with carbonates, 454–55
Hydrofluoric (HF) acid
  constants in HF-mineral reaction kinetics models, 456t
  dissolving power of, 451t
  reactions with sandstone minerals, 455–60
Hydrostatic pressure, 10–11

I

Inclined wells, skin components for, 126–27
Incompressible, single-phase flow of, 168–79
  annular flow, 179
  laminar or turbulent flow, 168–69
  pressure-drop calculations, 172–79
  velocity profiles, 169–72
Infinite-acting behavior, transition to pseudosteady state from, 29
Infinite-acting radial flow, 564, 566
Infinite-acting reservoir
  IPR calculations, 275–77
  prediction of production rate in, 25–26
  rate decline for, 26f
Infinite fracture conductivity performance, 574–78
Inflow performance for two-phase reservoir, 55–56
Inflow performance relationship (IPR), 11, 13, 14f, 34–37. *See also* IPR curve
  changes in, 267–68, 268f
  gas reservoirs, 270–73, 272f
  horizontal gas wells, 114–15
  pseudosteady-state, influence of average reservoir pressure, 35, 37, 37f
  skin effect on, 267, 267f
  steady-state, influence of skin effect, 35, 36f
  transient, 34–35, 36f, 87–91
  transient production rate forecast, 275–77
  of two-phase reservoirs, 268–70, 269f
  VFP and, combination of, 262–68
Initial reservoir pressure, 275
Injected gas
  bottomhole pressure, 313
  point of, 305–8
  pressure of, 304–5

Injection damage, 162–63
Injection rate, 472–96. *See also* Acid volume
Injection well diagnosis, 383, 384–85
Inside-casing gravel pack, 678, 679f, 680, 681f
In-situ average density, 194, 200, 201, 205, 207, 209
In-situ average liquid velocity, 198
In-situ stresses, 602–3
Integral of RNP (IRNP)
  computing, 398, 399f
  vertically fractured vertical well, diagnostic plot, 424f
Intermittent flow, 220–27
  plug, 221f, 222
  slug, 220, 221f, 222, 222f, 223f, 224f, 226
Intermittent gas lift, 300–301, 301f
Interstitial water saturation, 4
Inverse injectivity, 491
IPR curve, 262, 263f. *See* Inflow performance relationship (IPR)
  with declining reservoir pressure, 330f
  at different reservoir pressures, 331f
  in gas well deliverability, 271–73, 272f, 273f
  for oil well under pseudosteady-state conditions, 279f
  optimum gas-lift performance, 317–21, 317f, 321f
  for solution gas-drive reservoir, 292f
  for steady-state flow, 275
  transient, 275–77, 276f
  for two wellhead flowing pressures in two-phase reservoir, 270f
Isothermal compressibility, 75–76, 277
Isotropy, 112

J

Joshi model, 97–100
  schematic of, 97f
  well performance with, 99–100, 100f

K

KGD fracture model, 432, 433t
  with fracture width, 609–10, 614, 614f
Kinetic energy pressure drop, 217–19
  computing, 228, 230
  Δ in, meaning of, 234
  differential form of, 218–19
  due to change, 174–76
  neglecting, 228, 230, 235
  pressure gradient correlations, 226, 230, 231, 232
  in single-phase gas flow, 218
  in single-phase liquid flow, 217
  through choke, 240
Kinetics of a reaction, 453. *See also* Acid-mineral reaction kinetics

L

Laminar or turbulent flow, 168–69
Leakoff coefficient, 430, 432, 433t, 435
Lean gas reservoirs, 7
Limited-entry geometry, 411
Limited-entry vertical well, 410–12
  buildup analysis for, 413–14, 414f
  flow regimes for, 410–11, 410f
  log-log diagnostic plot, 412f
  test design, 415–16, 415f
Liquid density, 48–49, 49f
Liquid flow. *See also* Gas-liquid flow
  kinetic energy pressure drop in, 217
  pressure drop in water injection supply line, 218
  single-phase, 217–18, 240–41
Liquid holdup, 192
  Beggs-Brill correlation, 226–28
  Dukler correlation, 231–34, 233f
  Eaton correlation, 228–31, 229f
Liquids in gas wells, lifting, 359–61. *See also* Plunger lift
Logging while drilling (LWD), 2
Log-log diagnostic plot
  fracture calibration injection falloff, 430, 431f
  limited-entry vertical well, 412f
  well rate and pressure transient analysis, 395–96, 395f
Longitudinal fractures, 651, 651f
Low-conductivity vertically fractured vertical well
  buildup analysis for, 425–26
  production data analysis for, 426–28, 428f, 428t
Low-permeability reservoirs
  fractured well behavior in, 574–79
  production and reserves enhancement from, 561f
Low-pressure gas line, flow capacity of, 219–20
Low productivity, 372

M

Mandhane flow regime map, 223, 223f, 225, 226
Maps/mapping
  fracture height, 650f
  Gel frac *vs.* Waterfrac, comparison of, 649f
  with microseismic monitoring, 650f
  of multi-stage fracture treatment, 649f
  tiltmeter, 650
Matrix acidizing, 443–64
  vs. acid fracturing, 443
  acid-mineral reaction kinetics, 453–60
  acid-mineral reaction stoichiometry, 446–52
  acid transport to mineral surface, 460–61
  chemical reactions, primary, 448t
  in damaged and undamaged wells, benefits of, 444–46, 445–46f
  dissolving power of acids, 450t
  dissolving power of HF acid, 451t
  HCl preflush volume, calculating, 452
  introduction, 443–46
  molecular weights of species in, 449t
  precipitation of acid reaction products, 461–64
  spending of acid components, 451t
Matrix acidizing design for carbonates, 535–41
  acid selection design chart, 537f
  acid type and concentration, 535–36
  acid use guidelines, 536t
  acid volume and injection rate, 536–38
  fluid diversion in carbonates, 540–41
  monitoring the acidizing process, 538–40
  viscoelastic surfactant, 540–41, 541f
Matrix stimulation
  correlations of porosity *vs.* permeability and, 8
  near-wellbore permeability recovered or improved by, 9
  skin effect reduced or eliminated through, 13
Measurements
  acid-mineral reaction kinetics, 454
  along horizontal borehole, 393, 393f
  electrical resistivity formation, 5–6
  fracture geometry, 647–50
  fracture height with radioactively tagged proppant, 382–83, 384f
  petroleum thermodynamic properties, 7
  porosity, 3–4
  pressure, 14
  production logging, 14
  rate-*vs.*-pressure drop relationships, 14
  reaction kinetics, 454
  well testing, 2, 14
  wireline formation test, 392f, 393, 393f
Measurements while drilling (MWD), 2
Mechanical acid placement, 496–97
Mechanical damage, 156
Mechanical energy balance equation, 172, 179, 192, 193–94, 335
MH-B (modified Hagedorn-Brown method), 192–93
Microseismic monitoring, 648–50
  biwing fracture, events with, 648f
  map comparison of Gel frac *vs.* Waterfrac, 649f
  map of multi-stage fracture treatment, 649f
  mapping fracture height with, 650f
Minifracs, 303. *See also* Fracture calibration injection falloff
Mist flow
  annular, 222, 223f, 224f, 226
  distributed, 221f, 222, 222f
Mobility, 9
Model match
  buildup analysis, 409f, 414f
  fractured oil well, 422f
  parameters, 423t, 428t
Modified Hagedorn-Brown method (mH-B), 192–93
Mohr circle
  in drawdown failure condition, 666–67, 667f
  in formation sand production, 663, 663f
  Mohr-Coulomb criterion, 664–65, 664f, 666f
Moody friction factor chart, 176, 178f
Multilateral well technology, 116–17, 117f
Multiphase flow in wells, 184–213
  holdup behavior, 185–87
  pressure traverse calculations, 210–13
  two-phase flow regimes, 187–91
  two-phase pressure gradient models, 191–210
Multiple fracturing, well completions for, 652
  openhole fracturing, 652
  open hole with liners and sleeves for, 652–53, 653–54f
  perf and plug fracturing, 655
Multi-stage fracture treatment, map of, 649f

N

$N_{\mathrm{Ac},F}$ and $N_{\mathrm{Da},S}$, determining from data, 477–78, 478f
Natural gas
  correlations and calculations for, 66–76
  gas formation volume factor, 74–75

Natural gas (*continued*)
  gas gravity, pseudocritical properties from, 66–68
  gas isothermal compressibility, 75–76
  gas viscosity, 71–74, 72–73f
  gravity of, 62–63
  molecular weights and critical properties for, 62t
  nonhydrocarbon gases, 68–71
Natural gas reservoirs
  gas gravity, 61–63
  gas well deliverability, 76–84
  gas well transient flow of, 84–91
  introduction, 61–66
  production from, 61–91
  real gas law, 63–66
Naturally flowing well, 11
Near-well
  damage and perforations, 145
  radial flow, 9
Near-wellbore
  condition and damage characterization (*See* Skin effects)
  permeability, 9
  region, 20
  treatment (*See* Matrix acidizing)
  zones, 10, 10f
Net fracturing pressure, 616–20, 621
Net height, 4
Newtonian fluid
  non-, with fracture width, 613
  single-phase flow of compressible, 179–84
  single-phase flow of incompressible, 168–79
No-flow boundary reservoir, production from, 28–29
Nolte-Smith analysis pressure response modes, 647t
Nolte-Smith plot, 646–47, 647f
Non-Darcy flow
  coefficient, estimation of, 83
  in formation, correlations for, 81–82t
  fractured well performance, effect on, 579–85
  gas well deliverability, 79–84, 84f
  hydraulic fracturing for well stimulation, 579–85
Nonhydrocarbon gases
  gas compressibility factor correction for, 68–71
  presence of, 68
Non-Newtonian fluid with fracture width, 613
No-slip holdups, 186, 192
N_{Re} (Reynolds number), 168–69

O

Oil
  formation volume factor, 7–8
  inflow performance for two-phase reservoir, 55–56
  production gathering systems (*See* Surface gathering systems)
  reservoir, material balance for (*See* Oil material balance)
  in reservoir fluid, 4
  saturated, properties of, 42–52
  single-phase oil inflow performance relationships, summary of, 39
  undersaturated, transient flow of, 24–26
  understaurated oil reservoirs, production from, 19–39
  use of term, 4
  viscosity, estimating, 49–50
  water-oil ratio, 39
Oil and gas resource triangle, 585f
Oilfield units, 15–17
  converting to SI units, 16–17, 16t
Oil material balance, 277–86
  generalized expression, 281–82
  graph for two-phase reservoir, 286f
  production and fluid data, 284t
  under pseudosteady-state conditions, 278–80
  reservoir variables, calculating, 282–86
  saturated, 283–86
  straight lines for calculating, 282–83, 285t, 295
  undersaturated, 277–78
Oil-wet rocks, 4
Omana correlation, 244, 245, 246
Open hole
  completion, 10, 10f, 679, 680f
  fracturing, 652
  gravel pack, 678, 679f
  with liners and sleeves, 652–53, 653–54f
  log determination of porosity and fluid saturations, 366–68, 367f
  performance evaluation, 366–68
Opening time distribution factor, 625
Over flush, 625

P

Paccaloni
  design chart for monitoring acidizing, 489–90, 490f
  maximum Δp, maximum rate procedure, 489–90, 490f
Pad
  defined, 624
  volume calculations, total, 626–28
Partial completion
  radial flow, 411
  skin factor, 128–34
Particle plugging of pore spaces, 151–54
Particulate diverting agents, 497–508
  cake resistance, effect on acid placement, 506–8
  flow distribution during acidizing with, 502–6
  summary of, 498t
Payne et al. correction, 192, 204, 205
Pay thickness, 4
PCP (progressing cavity pump), 351f, 352–53, 352f
Penny-shaped fractures, 615
Penny-shaped model, 609
Perf and plug fracturing, 655
Perfect fracturing fluids, 646
Perforated liner completions, 146–48
Perforations
  acid volume design for ellipsoidal flow from, 479–80
  density, *vs.* productivity ratio, 672f
  ellipsoidal flow around, 476f
  flowing, in Frac-pack completion, 692
  in HPF, 696f
  in HPF, strategy for, 697–98
  near-well damage and, 145
Perforation skin effect
  calculating, 141
  for horizontal wells, 145–46
Performance curves, choke, 246–47, 247f
Permeability
  anisotropy (*See* Anisotropy)
  data, schematic of laboratory-derived, 54f
  effect of, on oil flow in two-phase reservoir, 54–55
  effects of, 37–39
  flow regime analysis, 401
  fluid damage and, 155–56
  models, 483–85
  in petroleum production system, 8–9
  vs. porosity, 8
  response to acidizing, 485
  values, 37–39
  water production, 37–39, 38f
Petroleum production engineering, role of, 1–17
  introduction, 1–2
  petroleum production system, components of, 2–11
  units and conversions, 15–17
  well productivity and production engineering, 11–15
Petroleum production system, components of, 2–11
  permeability, 8–9
  reservoir hydrocarbons, volume and phase of, 2–8
  surface equipment, 11
  well, 10–11
  zone near well, sandface, and well completion, 9–10
Petroleum thermodynamic properties, 7
Phase diagram, 6, 6f, 7
Piceance Basin stratigraphic column, 586, 587f
PKN fracture model, 433t, 434
  with fracture width, 609, 610–13, 611f
Plug flow, 221f, 222
Plunger lift, 359–61
  life cycle, 360, 361f
  operation, 360f
  principle of, 360
  purpose of, 359–60
  well completion, 360, 361f
Plunger stroke length, 340–41
Pore spaces, particle plugging of, 151–54
Porosity, 3–4
  vs. permeability, 8
Positive-displacement pumps, 335, 338–53
  progressing cavity, 352–53
  sucker rod pumping, 338–52
Postflush, 511
Potential energy change, pressure drop due to, 173–74
Potential energy pressure gradient, 192
Power law
  fluids, rheological properties of, 640–41
  fracture surface growth assumption, 430, 432
  model, 172
Precipitate zone, effect on well productivity, 462–63, 464f

Precipitation models, 482–83, 483f
Precipitation of acid reaction products, 461–64
Preflush and postflush design, 509–11
  HCl preflush, 509–11
  postflush, 511
Pressure buildup
  analysis, 406–7, 410f
  test, 394, 394f
Pressure depletion, gas-oil ratio *vs.,* 294f
Pressure drawdown equation, 25
Pressure drawdown-related problems, 13
Pressure drop
  in high-rate horizontal well, 252–54
  horizontal well flow profile with small choke size, 255f
  importance of, 250–52
  kinetic energy, 217–19
  relative, 251–52
  single-phase flow, 252
  two-phase flow, 252–56
  in water injection supply line, 218
  wellbore *vs.* reservoir, 251t
Pressure-drop calculations, 172–79, 235–36, 238–39t, 249t
  Δp_F, frictional pressure drop, 176–79
  Δp_{KE}, pressure drop due to kinetic energy change, 174–76
  Δp_{PE}, pressure drop due to potential energy change, 173–74
  pressure traverse, 235–36
Pressure drop equation, 179–82
Pressure gradient, 10–11
  correlations, 226
  curves, 213, 213f
  kinetic energy pressure drop in, 226, 230, 231, 232
  models, two-phase, 191–210
Pressure gradient calculations
  Beggs-Brill correlation, 227–28
  Dukler correlation, 232–34
  Eaton correlation, 230–31
Pressure-normalized rate, 397–98
Pressure profiles in well, 336f
Pressure radius of investigation, 396–97
Pressure traverse calculations, 210–13, 234–36
  with fixed length interval, 211–13
Pressure-volume-temperature (PVT). *See* PVT (pressure-volume-temperature) properties
Prime mover power requirements, 341–45
Production damage, 161–62
Production data analysis methods, 397–98, 399f
Production engineer, 11–14
Production engineering, objectives of, 11–14
Production log evaluation, 370–87
  abnormally high injection rate, 385–87, 386f
  bottomwater production, excessive, 380–81
  cased hole formation evaluation, 369–70
  cement evaluation, 368–69, 369f
  channeling, 374–375f, 374–76, 376f
  example of, 371f
  flow profile used to evaluate damaged well, 372
  fracture height, 381–83, 384f
  gas coning, 379–80, 380f
  gas production, excessive, 374
  gas production from thief zone, excessive, 378–79, 378f
  high-permeability layers, preferential flow through, 376–77, 377f
  injection well diagnosis, 383, 384–85
  low productivity, 372
  production logging, 372–74, 373f, 381
  water coning, 379–80, 379f
  water production, excessive, 374
Production logging
  strategy and analysis, 372–74, 373f
  for well treatment evaluation, 381
Productivity index, 11–13
  dimensioned, 12–13
  dimensionless, 13, 28
  maximizing, in cost-effective manner, 22
Progressing cavity pump (PCP), 351f, 352–53, 352f
Property correlations for two-phase systems, 47–52
  downhole properties, estimating, 51–52
  liquid density, 48–49, 49f
  oil viscosity, 49–50
  water presence, accounting for, 50–52
Proppant
  characteristics of, 642
  closure stress *vs.* proppant conductivity, 643, 644f
  commonly used, 642, 643f
  fluid volume requirements, 624
  fracture conductivity and, 642–46
  propped fracture conductivity, 643–45
  schedule, 629–30, 631f
  settling velocities, 645–46
  transport, 645
Propped fracture
  vs. acid fracture performance, 553–54

  conductivity, 643–45
  width, 631–35
Pseudocritical properties from gas gravity, 66–68, 67f
Pseudolinear flow, 416, 416f, 418–20
Pseudoradial flow, 416, 416f, 418–20
Pseudosteady-state flow, 26–29, 103–13
  Babu-Odeh model, 103–9
  Economides et al. model, 109–13
  IPR curves, 34, 37f
  production forecast under, 278–80
  production from no-flow boundary reservoir, 28–29
  transition to pseudosteady state from infinite acting behavior, 29
Pseudo-three-dimensional (p3-D) model, 609
p3-D (pseudo-three-dimensional) model, 609
Pump-assisted lift, 335–61
  dynamic displacement pumps, 354–59
  introduction, 335–37
  liquids in gas wells, 359–61
  positive-displacement pumps, 338–53
  pressure increase from downhole pump, 337
Pump efficiency, effect of gas on, 350–52
Pumping, frictional pressure drop during, 641–42
PVT (pressure-volume-temperature) properties, 7, 43–46
  below bubble-point pressure, 43, 45f
  of saturated oil reserves, obtaining, 44, 46f

R

Radial flow geometries for vertical wells, 405
Radial fracture model, 432, 433t
  with fracture width, 609, 615
Radial fractures, 615
Rate decline data, recovery from, 388–90, 389f
Rate-normalized pressure (RNP), 397–98. *See also* Integral of RNP (IRNP)
Rate transient analysis (RTA), 387–90. *See also* Well rate and pressure transient analysis
Reaction kinetics. *See* Acid-mineral reaction kinetics
Real gas law, 63–66
Real gas pseudopressure, 88–90t
Relative permeability. *See* Permeability
Relative roughness, 176, 177f
Reservoir, 2–3
  classification of, 6–7
  fluid, components of, 11
  height, 4
  HPF properties, 697t
  limited production rate, 273
  permeability, 401
  pressure, estimating, 405–6
  schematic showing, 3f
  thickness, 4
Reservoir hydrocarbons, volume and phase of, 2–8
  areal extent, 7–8
  classification of reservoirs, 6–7
  fluid saturations, 4–6
  porosity, 3–4
  reservoir, 2–3
  reservoir height, 4
Reservoir rock, fracturing of, 602–9
  breakdown pressure, 602, 604, 605, 605f, 606f
  critical depth for horizontal fracture, 607–8, 608f
  fracture direction, 606–7, 608–9
  fracture initiation pressure, calculating, 606
  in-situ stresses, 602–3
  stresses *vs.* depth, 604
Reservoir variables, calculating, 282–86
  saturated reservoirs, 282
  undersaturated reservoirs, 282–86
Resistivity log, 5–6, 5f
Retrograde condensate reservoir, 7
Retrograde condensation region, 7
Revaporization, 7
Reynolds number (N_{Re}), 168–69
Rheological properties of fracturing fluids, 636–41
  of borate-crosslinked fluid, 638–39f, 638–40
  determination of, of power law fluids, 640–41
Rod pump performance, analyzing from dynamometer cards, 347–50
Ros correlation, 243, 244–46, 244t

S

Sand exclusion, 677–98
  Frac-pack completion, 688–93
  gravel pack completion, 678–88
  high-performance fractures, 693–98
Sandface, in petroleum production system, 9–10
Sand flow modeling, 662–75
  formation sand production, factors affecting, 662–72
  in wellbore, 672–75

Sand management, 676–77
  cavity completion, 677
  completion failure avoidance, 698–99
  introduction, 661
  sand exclusion, 677–98
  sand flow modeling, 662–75
  sand production prevention, 676–77
Sand problems, events to induce, 663f
Sand production prevention, 676–77
Sandstone acidizing design, 469–513
  acid additives, 512
  acidizing treatment operations, 512–13
  acid selection, 470–71, 471t
  acid volume and injection rate, 472–96
  fluid placement and diversion, 496–509
  introduction, 469–70
  permeability response to, 485
  preflush and postflush design, 509–11
Sandstone acidizing models, 472–85
  acid and fast-reacting mineral concentration profiles, 475f
  acid volume design for ellipsoidal flow from perforation, 479–80
  acid volume design for radial flow, 478–79
  acid volume needed to remove drilling mud damage, 480–81, 481f
  dimensionless groups in, 476t
  ellipsoidal flow around perforation, 476f
  $N_{\mathrm{Ac},F}$ and $N_{\mathrm{Da},S}$, determining from data, 477–78, 478f
  permeability, 483–85
  precipitation, 482–83
  two-acid, three-mineral, 481–82
  two-mineral, 472–81
Sandstone minerals
  fluosilicic acid reactions with, 460
  HF acid reactions with, 455–60
  relative reaction rates of, 459
Saturated oil, properties of, 42–52
  bubble-point pressure and, 42–43, 45f
  correlations to obtain PVT properties of, 44, 46f
  general, 42–46
  two-phase systems, property correlations for, 47–52
Saturated reservoirs, 6
  material balance for, 283–86
  variables, calculating, 282
SCF (standard cubic ft), 8
Screenout, 608, 625
Screen sizing, 682–86, 683–84t
Segregated flow, 220–26
  annular, 220, 221, 221f, 222, 223f, 224f, 226
  stratified, 220–21, 221f, 223f, 224f
  wavy, 220, 221, 221f
Semi-analytical modeling approach, 590
Separation facility, 11, 13
Settling velocities, 645–46
$S_{H,}$ calculation of, 141–42
Shale reservoirs, 586–92
  decline curve analysis, 590, 591f
  dual-porosity approach, 592
  fracture patterns, 586–89, 588f, 589f
  productivity of fractured horizontal wells in, predicting, 588, 589–90, 589f
  semi-analytical modeling approach, 590
Single-phase flow regimes
  of compressible, Newtonian fluid, 179–84
  gas, 218–20, 241–43
  of incompressible, Newtonian fluid, 168–79
  liquid, 217–18, 240–41
  oil inflow performance relationships, summary of, 39
  VFP combined with IPR, calculating, 262–64, 264f
  wellbore pressure drop for, 252
SI units, 15–17
  converting to oilfield units, 16–17, 16t
Skin components
  inclined wells, 126–27
  partial completion, 128–34
  vertical wells, 126–27
  well deviation, 128–34
Skin effects, 121–63
  deviated, 126, 130
  evolution, carbonate acidizing design, 539–40, 540f
  formation damage mechanisms, 151–57
  formation damage sources, 157–63
  Hawkins' formula, 122–26
  horizontal well damage skin effect, 134–37
  hydraulic fracturing for well stimulation, 562–66, 565f
  introduction, 121–22
  IPR, 35, 36f, 267, 267f
  matrix stimulation to reduced or eliminate, 13
  perforation, 141, 145–46
  phase change-dependent, 124
  well deliverability, 267, 267f

Skin factors, 138–51. *See also* Well completion skin factors
  acid treatment data, 492t
  anisotropy, 134
  calculating, 490–94
  cased well completion, 138–46
  evolution during acidizing, 486f, 490–93, 493t, 494f
  example results, 493t
  flow regime analysis, estimating, 405
  Frac-pack completion, 690–91
  gravel pack completion, 148–51
  injection rate, effect of, 486f
  limited-entry vertical well, 413
  partial completion, 128–34
  viscous, in gas well treatment, 495–96, 496f
Sleeves, 653
Slip velocity, 186–87, 672
Slotted liners, 10, 10f
Slotted or perforated liner completions, 146–48
Slug flow, 188, 191, 220, 221f, 222, 222f, 223f, 224f, 226
Slurry packing, 686
Solution gas drive, 286–94, 292f
Sour gas, 68
  gas compressibility factor of, 70–71, 70t
  viscosity of, calculating, 74
Spontaneous potential (SP), 4, 5f
Standard conditions, 4, 7–8
Standard cubic ft (SCF), 8
STB (stock tank barrels), 8
Steady-state flow
  IPR curve for, 275
  VFP curve for, 275
Steady-state performance, 19–24, 97–103
  effect of drainage area on, 23, 24t
  Furui model, 100–103
  Joshi model, 97–100, 97f
  production rate calculation and rate improvement, 22–23
  schematic for, 20f
Stepwise calculation procedure. *See* Pressure traverse calculations
Stimulated reservoir volume (SRV), 562f, 588
Stock tank barrels (STB), 8
Stratified flow, 220–21, 221f, 223f, 224f
Stresses
  vs. depth, 604
  in-situ, 602–3
Stripper wells, 39
Sucker rod pumping, 338–52
  beam loads, 345–47
  beam pumping units, 345, 345t
  equipment, 338–39, 338–39f
  gas, effect on pump efficiency, 350–52, 350f
  performance, analyzing from dynamometer cards, 347–50
  prime mover power requirements, 341–45
  rod load service factors, 347t
  speed, calculation of required, 339–40
  steel sucker rod and tubing properties, 342–43t
  stroke length, 340–41
  volumetric displacement with, 339–40
Surface equipment, in petroleum production system, 11, 12f
Surface gathering systems, 247–50, 248f, 249f
  analysis of, 248–49
  pressure distribution in, 250f
  pressure drop calculation results, 249t
s_V, calculating, 142
s_{wb}, calculating, 143–45
Sweet gas, 68

T

Taitel-Dukler flow regime map, 190–91, 190f, 223, 224f
Tarner's method, 287–88, 290t
Taylor bubbles, 188
Telltale screen, 680
Temperature, 650
Test design, limited-entry vertical well, 415–16, 415f
Theile modulus, 522
Thief zone. *See* High-permeability layers
3-D model, 609
3-D techniques, 7
Three-well fault block, 32–34, 32f
Tight gas reservoirs, 586, 588f
Tiltmeter mapping, 650
Time-averaged quantity, 185
Time-distance diagram showing regions of precipitation, 482–83, 482f
Tip screenout (TSO) treatments, 608, 615
Total compressibility, 278, 283
Tracers, 650

Transient IPR curves
  curves for, 91f
  for gas well, 87–91
  inflow performance relationship, 34–35, 36f
  viscosity, gas deviation factor, real gas pseudopressure for, 88–90t
Transient production rate forecast, 275–77, 276–77f
Transiet well analysis, 387–437
  Arps decline curve analysis, 388, 388t, 390
  expected ultimate recovery, 388–90, 389f
  flow regime analysis, 400–437
  formation fluid sampling, 391–93
  limited-entry vertical well, 410–12
  rate transient analysis, 387–90
  well rate and pressure transient analysis, 393–99
  wireline formation test, 390–93
Transport proppants, 645
Transverse fractures
  horizontal well fracturing, 651, 651f
  hydraulic, choke effect for, 592–94
Treatment design, competing factors influencing, 472
TSO (tip screenout) treatments, 608, 615
Tubing
  balance point of, 306, 307f
  limited wells, 273
  performance curve, 306, 308f
  pickling, 513
Tubing size
  vs. gas-lift requirements, 326–27, 327f, 328f, 329f
  in gas well deliverability, 272–73, 273f
2-D model, 609–10. *See also* Fracture width
Two-acid, three-mineral model, 481–82
Two-mineral model, 472–81
  acid and fast-reacting mineral concentration profiles, 475f
  acid volume design, 478–80
  acid volume needed to remove drilling mud damage, 480–81, 481f
  dimensionless groups in, 476t
  ellipsoidal flow around perforation, 476f
  $N_{\mathrm{Ac},F}$ and $N_{\mathrm{Da},S}$, determining from data, 477–78, 478f
Two-phase correlations for horizontal well inflow, 115–16
Two-phase flow regimes, 187–91, 189f
  description of, 188, 189f
  in horizontal pipes, 220–36
  map, 188, 190–91
  original Hagedorn-Brown correlation, 193–98
  predicting, 191
  in reservoir, 53–55
  schematic of, 185f
Two-phase pressure gradient models, 191–210
  Beggs-Bill method, 201–6
  bubble flow: Griffith correlation, 198–201
  flow regimes other than bubble flow: original Hagedorn-Brown correlation, 193–98
  Gray correlation, 206–10
  modified Hagedorn-Brown method, 192–93, 266, 266t
  relative performance factors, 193t
Two-phase reservoirs, 6
  IPR and VFP of, 268–70, 269f
  material balance graph for, 286f
  production forecast from, 286–94
Two-phase reservoirs, production from
  Fetkovich's approximation, 57–58
  flow, 53–55
  introduction, 41–42
  oil inflow performance, 55–56
  production from, 41–58
  property correlations for, 47–52
  saturated oil, properties of, 42–52
  Vogel inflow performance, 55–57, 57f

U

Unconventional resources, 585. *See also* Shale reservoirs; Tight gas reservoirs
Underreamed casing completions, 679, 680f
Underreamed-casing gravel pack, 678, 679f
Undersaturated oil, transient flow of, 24–26
Undersaturated reservoirs, 6
  material balance for, 277–78
  variables, calculating, 282–86
Understaurated reservoirs, production from, 19–39
  inflow performance relationship, 34–37
  introduction, 19
  pseudosteady-state flow, 26–29
  single-phase oil inflow performance relationships, summary of, 39
  steady-state performance, 19–24
  undersaturated oil, transient flow of, 24–26
  water production, relative permeability, effects of, 37–39
  wells draining irregular patterns, 30–34

Unified fracture design, 567–73
Units and conversions, 15–17, 404t

V

Valves, equivalent lengths of, 238–39t
Velocity profiles, 169–72
Vertical flow performance (VFP), 11, 13, 14f. *See also* VFP curve
  of gas reservoirs, 270–73, 272f
  GLR's impact on, 264–65
  IPR and, combination of, 262–68, 263f
  transient production rate forecast, 275–77
  of two-phase reservoirs, 268–70, 269f
Vertically fractured vertical well, 416–28
  flow regimes, 416–19, 416f
  high-conductivity, 420–24, 423f
  IRNP diagnostic plot, 424f
  low-conductivity, 425–28, 428f, 428t
  model match parameters, 422f, 423t, 428t
  pressure buildup data, 424f
Vertical permeability, 401
Vertical-to-horizontal anisotropy, 95, 97–98, 112
Vertical wells, skin components for, 126–27
VES (viscoelastic surfactant), 540–41, 541f
VFP. *See* Vertical flow performance (VFP)
VFP curve, 262, 263f. *See also* Vertical flow performance (VFP)
  in gas well deliverability, 271–73, 272f, 273f
  for oil well under pseudosteady-state conditions, 279f
  for solution gas-drive reservoir, 292f
  for steady-state flow, 275
  transient, 275–77, 276f
  for two wellhead flowing pressures in two-phase reservoir, 270f
Viscoelastic surfactant (VES), 540–41, 541f
Viscosity, calculating
  gas, 71–74, 72–73f
  oil, 49–50
  sour gas, 74
  transient IPR for gas well, 88–90t
Viscous diversion, 508–9
Vogel inflow performance, 55–57, 57f
Void fraction, 186
Volume equalized power law, 640–41
Volumetric flow rate, 168–69, 170f
Volumetric model, 526–29, 528–29f

W

Water
  flow through high-permeability layers, 376–77, 377f
  presence of, accounting for, 50–52
  in reservoir fluid, 11
  sensitivity, 154
Water block, 156
Water coning, 379–80, 379f
Water injection supply line, pressure drop in, 218
Water-oil ratio, 39
Water production
  excessive, in production log evaluation, 374
  relative permeability, effects of, 37–39, 38f
Water-wet rocks, 4
Wavy flow, 220, 221, 221f
Well
  configuration, 336f
  deviation, skin from, 128–34
  draining irregular patterns, 30–34
  performance enhancement, 13–14
  petroleum production system, 10–11
  pressure profiles, 336f
  stimulation (*See* Hydraulic fracturing for well stimulation)
  zone near, 9–10
Wellbore, sand flow in, 672–75
  sand accumulation in wellbore, 675
  sand erosion, 675
  sand production to surface, 673–75, 674f
Wellbore crossflow, 392
Wellbore flowing pressure, 19
Wellbore flow performance, 167–213
  introduction, 167
  multiphase flow in wells, 184–213
  single-phase flow of compressible, Newtonian fluid, 179–84
  single-phase flow of incompressible, Newtonian fluid, 168–79
Wellbore pressure drop. *See* Pressure drop
Well completion
  in petroleum production system, 9–10
  techniques, 9–10, 10f
Well completion, cased and perforated, 138–46
  near-well damage and perforations, 145
  perforation skin effect, calculating, 141
  perforation skin factor for horizontal wells, 145–46

Well completion, cased and perforated (*continued*)
  s_H, calculating, 141–42
  s_V, calculating, 142
  s_{wb}, calculating, 143–45
Well completion skin factors, 138–51
  cased, perforated completions, 138–46
  gravel pack completions, 148–51
  slotted or perforated liner completions, 146–48
Well deliverability, 261–73
  analysis, 19
  bottomhole flowing pressure, 261
  declining reservoir pressure, 267–68, 268f
  gas, 270–73, 272f
  introduction, 261–62
  IPR and VFP, combination of, 262–68, 263f
  skin effect, 267, 267f
  two-phase reservoir, 268–70, 269f
Wellhead
  assembly, 1, 12f
  flowing pressure, 265–67, 266f, 269f
Well logging techniques, 4
Well performance evaluation, 13–14, 365–437
  cased hole logs, 368–87
  introduction, 365–66
  open-hole performance evaluation, 366–68
Well production forecast, 275–96
  depleting pressure, cumulative, 291t
  gas well performance, 294–96, 296t
  introduction, 275
  material balance, 277–86
  production and fluid data, 284t
  production rate, incremental, and total cumulative recovery, 280t
  under pseudosteady-state conditions, 278–80
  rate *vs.* time, 276–77, 277f
  Tarner's method, 287–88, 290t
  transient production rate forecast, 275–77, 276–77f
  two-phase reservoir, production forecast from, 286–94, 293t
Well productivity and production engineering, 11–15
  organization of book, 14–15
  production engineering, objectives of, 11–14
Well rate and pressure transient analysis, 393–99
  IRNP, 398, 399f
  log-log diagnostic plot, 395–96, 395f
  pressure buildup data, 394, 394f
  pressure radius of investigation, 396–97
  production data analysis methods, 397–98, 399f
Well testing, 1
  areal extent and, 7
  measurements, 2, 14
  purpose of, 14
Wettability changes, fluid damage and, 155–56
Wirelineformation test, 390–93
  differential depletion, 392, 393
  horizontal borehole, 393, 393f
  measurements, 392f, 393, 393f
  multiprobe formation test, 391, 391f
  reservoir description, 392f
Wormhole formation and growth, 522–25
  from acid injection into a perforated completion, 521f
  acid volumes needed to propagate wormholes through linear San Andres dolomite cores, 525f
  conical wormhole forms, 523
  in large block experiment, 520f
  morphologies at different injection rates, 521f
  post-stimulation buildup test data for carbonate matrix acidizing, 522f
  propagation efficiency, 525f, 535f
  structures created by different injection rates, 524f
  Theile modulus, 522
Wormhole propagation models, 525–35
  Buijse-Glasbergen model, 529–31, 531f
  Furui et al. model, 531–35, 534f
  volumetric model, 526–29, 528–29f

X

Xiao et al. correlation, 226

Z

Zone near well, 9–10