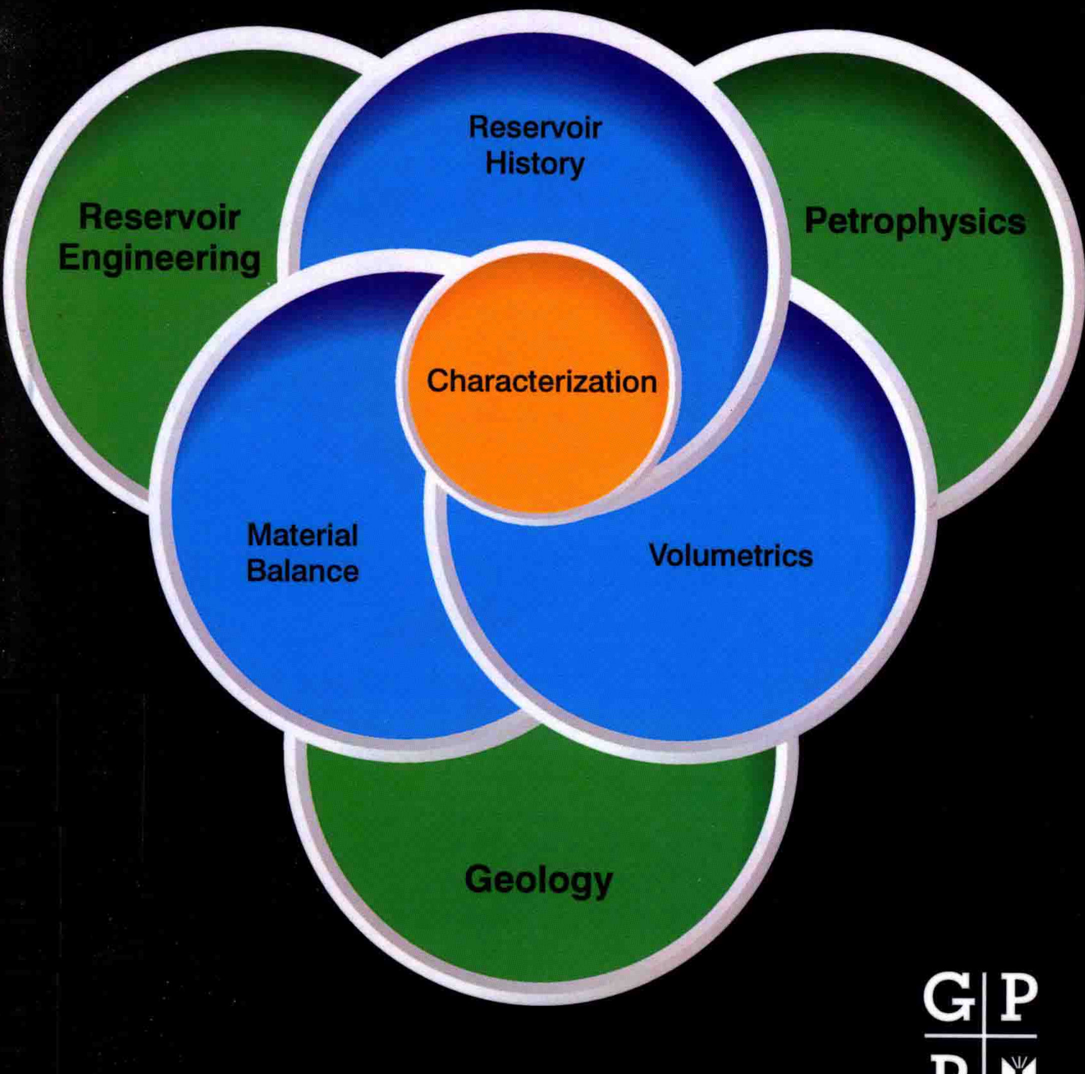
# Practical Reservoir Engineering and Characterization

Richard O. Baker • Harvey W. Yarranton • Jerry L. Jensen




G|P
P|

# Practical Reservoir Engineering and Characterization

*Richard O. Baker*
Independent Consultant

*Harvey W. Yarranton*
Department of Chemical and Petroleum Engineering, University of Calgary, Canada

*Jerry L. Jensen*
Department [illegible]etroleum Engineering, [illegible]gary, Canada

ELSEVIER

AMSTERDAM • BOSTON • HEIDELBERG • LONDON
NEW YORK • OXFORD • PARIS • SAN DIEGO
SAN FRANCISCO • SINGAPORE • SYDNEY • TOKYO
Gulf Professional Publishing is an imprint of Elsevier

G P
P

Gulf Professional Publishing is an imprint of Elsevier
225 Wyman Street, Waltham, MA 02451, USA
The Boulevard, Langford Lane, Kidlington, Oxford, OX5 1GB, UK



ISBN: 978-0-12-801811-8

**Library of Congress Cataloging-in-Publication Data**
A catalogue record for this book is available from the Library of Congress

**British Library Cataloguing-in-Publication Data**
A catalogue record for this book is available from the British Library

For information on all Gulf Professional Publishing publications visit our website at http://store.elsevier.com/

# Practical Reservoir Engineering and Characterization

# Dedications

To my family, my friends, and to God … R.B.

To my family and the many colleagues who inspired the work … H.W.Y.

To the glory of God and to my parents, Jean, Jim, and Mary … J. L. J.

# Preface

*The most valuable reservoir engineers are those who see the clearest and the most and who know what they are looking for.*

*Dake (1992)*

Reservoir characterization sounds simple: determine the size, shape, and property distribution of a reservoir. And yet, an engineer's first encounter with reservoir characterization can be a shock. He cannot see or touch the reservoir. Like the proverbial blind man feeling an elephant, he must construct a mental picture of the reservoir from indirect information. This information must be interpreted from logs and cores, pressure measurements, fluid properties, and production data. These data are often sparse, incomplete, noisy, and sometimes nonexistent. From this murky picture, he must answer questions that impact the value of the company, such as the following:

- What is the original oil in place?
- What is the remaining recoverable oil in place?
- Where is the remaining oil located and under what conditions (pressure and saturation)?
- How can the remaining oil be recovered?
- What is the drive mechanism of the reservoir?
- What is needed to optimize recovery?
- Can oil rates and reserves be economically increased?

Clearly, there can be considerable subjective judgment in reservoir characterization and reservoir engineering. The goal of this book is not only to teach the ideas and methods of reservoir characterization, but also to provide a guide for some of the subjective judgments. The book is divided into three parts. The first part reviews the engineering fundamentals needed for reservoir characterization. The second part addresses the sources and analysis of reservoir engineering data including methods to estimate unknown properties. The third part presents reservoir characterization methods and demonstrates how to integrate results from different methods into a self-consistent reservoir characterization.

We emphasize that reservoir characterization is an integrated, iterative process that must contend with uncertainty. The focus of this text is on understanding and using commonly available data to contribute to this process. It is necessary to make some assumptions to even begin a reservoir characterization. For example, it may not be possible to determine the strength of an aquifer or the connectivity in the reservoir from initial static data sources (such as logs and cores). These characteristics are assumed and later refined based on dynamic data sources (such as pressure and production). It is extremely important that the engineer or geoscientist should not be afraid to make an assumption and see how that assumption and the corresponding calculations fit the data. It is also important to periodically check the underlying assumptions and the data interpretation. This constant active feedback loop continuously improves the reservoir concept as new data are collected and economics change. Initial estimates to the previous list of questions will, at best, be in the plus or minus 40% range but, with more wells and dynamic data, our answers should converge to be in the plus or minus 10% range at least for field scale parameters. Unfortunately, for local regions within the reservoir and at individual wells, the errors increase again. Dealing with uncertainty is one of the main challenges in reservoir characterization.

There are many excellent books on reservoir engineering, most focusing on engineering principles. This book is different because reservoir engineering and geological principles are demonstrated on many examples of real field data with all its inherent gaps and inconsistencies. It is important to see and use real field data because one of the challenges subsurface scientists face is interpreting noisy and incomplete data and transforming it to knowledge of fluid flows. There are large gaps in our reservoir knowledge because we sample only approximately one ten-billionth of the reservoir with core and logs and pressure and fluid property data are often incomplete. Therefore, methods to estimate properties when data are missing are presented. We emphasize the integration and cross-checking of data and methods. It is our strong opinion that both static data (such as facies and permeability) and dynamic data (such as pressure and production rates) must be analyzed and interpreted together to reduce uncertainty and cross-validate reservoir and fluid parameters.

One note of caution: we have used many field examples and, in many cases, provided an interpretation of the data. We cannot guarantee that the interpretation is correct or that the methods we propose will provide the best characterization of a given reservoir. Old interpretations can always be overturned by new data. Each reservoir is unique and each engineer must fashion a characterization from the data and methods available as best as he or she can. Solving the puzzle of reservoir characterization is a creative act and one of the most satisfying in our engineering experience. For the novice, we hope this book can help guide you in this experience. For the veteran, we hope you find this a useful reference with some new insights.

The authors would like to express gratitude to the many people who have contributed to this text. Richard would like to thank Shelin Chugh, Rod Batycky, Edwin Jong, Kerry Sandhu, Cameron McBurney, Nathan Meehan, Robert Jobling, and Gord Moore who have contributed greatly to the thought process. Harvey is in addition grateful to Susan Biolowas, Rupam Bora, Enrico DeLauretis, Dennis Beliveau, Bette Harding, Sonja Malik, Bob McKishnie, Greg Osiowy, Vladimir Vikalo, and Claudio Virues for their suggestions and assistance and to Mehran Pooladi-Darvish and Steve Ewan from Fekete & Associates for their help with the PTA figures and discussion. Jerry would like to thank Patrick Corbett, Larry Lake, Chris Clarkson, Rudi Meyer, Steve Hubbard, Fed Krause, Per Pedersen and his students for lively, thought-provoking discussions. We are especially indebted to our wives and our families, Karen Baker, Stewart and Dorothy Baker, Maureen Hurly, and Jane Jensen for their patience and encouragement.

# Contents

# Introduction

# 1

## Chapter Outline



Petroleum is a hydrocarbon mixture derived from organic material. It can exist as a solid (coal), a liquid (oil), or a gas (natural gas). This book is primarily concerned with oil, although, as we shall see, gas and water are always associated with oil. Before considering oil reservoir engineering, let us review where oil is found and how oil is produced.

A common misconception is that oil and natural gas are found in underground caverns. In fact, oil and gas are found within the microscopic pores of rocks, Figure 1.0.1. A rock formation that contains petroleum is termed a petroleum-bearing reservoir. Not all petroleum reservoirs are productive. Petroleum must be able to flow through the pore spaces of the formation. Hence, the pores must form a connected network. The term permeability is defined as a measure of the flow capacity of this pore network. Petroleum can only be economically produced from a reservoir with sufficient permeability. The permeable rock formation must also be overlain by impermeable rock, forming a trap that prevents the petroleum from migrating out of the reservoir. Figure 1.0.2 shows a schematic of a trapped hydrocarbon deposit.

To produce petroleum, wells are drilled into the reservoir. The pressure in the wellbore is lower than in the reservoir, and reservoir fluid flows into the wellbore and up to surface. As shown in Figure 1.0.3, there are several types of wells,

**Practical Reservoir Engineering and Characterization. http://dx.doi.org/10.1016/B978-0-12-801811-8.00001-8**

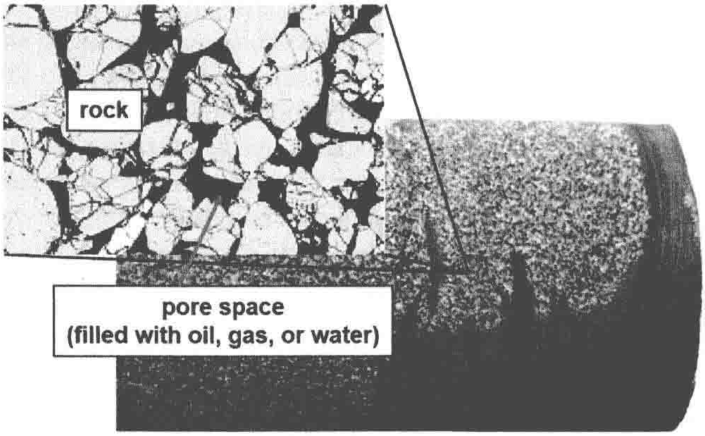



**Figure 1.0.1** Photograph of a core cut from a reservoir and a micrograph of a thin section from a core. The black regions in the micrograph are the pore space, while the dark and light grey areas are the solid rock.
Images from: http://rockhou.se/page/3/ and http://ior.senergyltd.com/issue8/pnp/herriot_watt/, January 7, 2012.

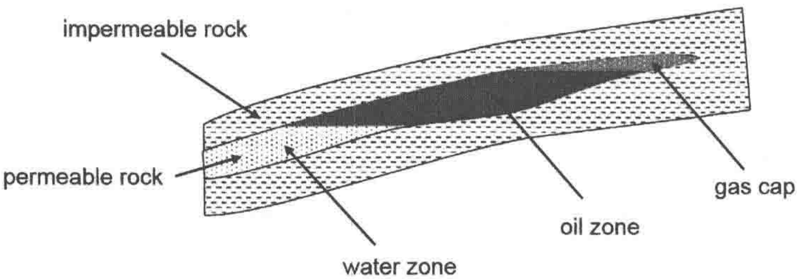



**Figure 1.0.2** Hydrocarbon trap containing oil and gas.

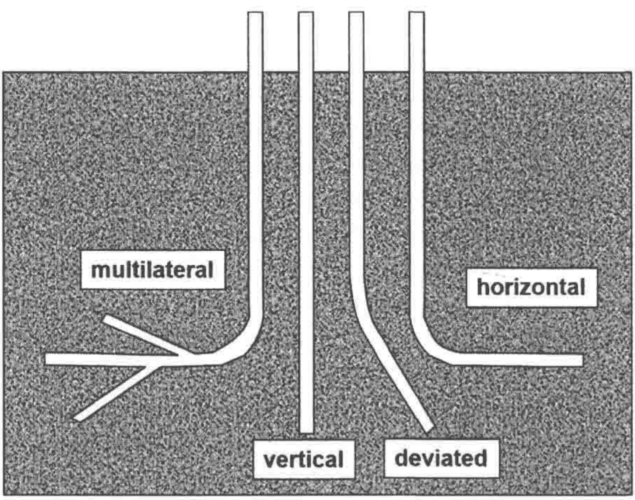



**Figure 1.0.3** Types of wells.

including vertical, deviated, horizontal, and multilateral. Historically, most wells are vertical wells. Vertical wells contact the full height of the reservoir, but through a single hole that is usually less than a foot in diameter. Deviated wells are vertical wells drilled at an angle up to about 65°. Deviated wells are used when it is necessary to drill underneath a surface obstacle, such as a lake, or when many wells are drilled from a single drilling platform. Horizontal wells are a relatively recent technical advance. They can contact a large reservoir area, but may not contact the full height of a reservoir. Multilaterals are horizontal wells with extensions added to the main bore hole.

There are also different approaches to making the wellbore ready to produce fluids, that is, completing the well. Some wells are open hole at the formation of interest. Most wells are cased; that is, steel pipe is cemented in the drilled hole to prevent hole collapse and fluid migration from one formation to another. The casing is then perforated; holes are made through the casing into the formation so that reservoir fluid can reach the wellbore. Schematics of some different completion types are provided in Figure 1.0.4.

In some cases, the formation around the well is stimulated, typically through acid injection or hydraulic fracturing. Acid injection can dissolve material near the wellbore that may be restricting production. Hydraulic fracturing involves injecting fluid at high pressure to crack open the formation. Proppants (solid particles such as sand or ceramic beads) are injected into the open fractures to hold the fracture open after the pressure is reduced. The propped fractures create two planar conduits for fluid flow. Once the well is drilled and completed, production tubing is placed in the

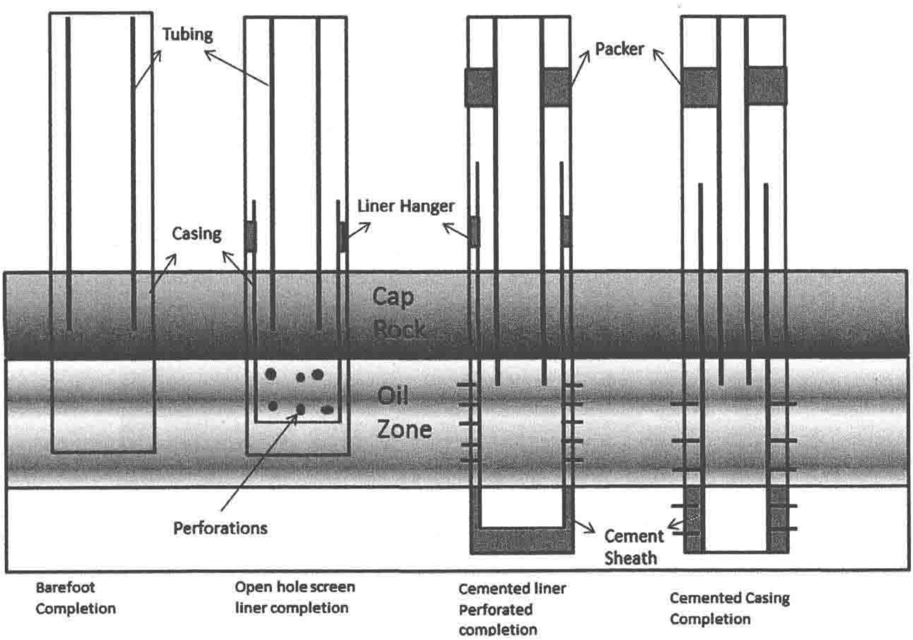



**Figure 1.0.4** Schematics of four methods of well completion. Other configurations are also possible.

well, and the reservoir fluids are produced. A pump may be added to reduce the pressure in the wellbore and increase production rates. A schematic of a producing well is provided in Figure 1.0.5.

Once reservoir fluids reach the surface, they are separated into gas, oil, and water streams. An oilfield surface facility is shown in Figure 1.0.6. Gas, liquid, and water flow rates are measured for each well or group of wells so that the produced volumes can be allocated to the owners of the wells. Gas is compressed and sent by pipeline to a gas plant for further processing. Sometimes in remote locations or due to lack of market for gas, the gas is flared. Oil is sent to an oil pipeline and eventually to a refinery. Water is usually re-injected into a suitable formation.

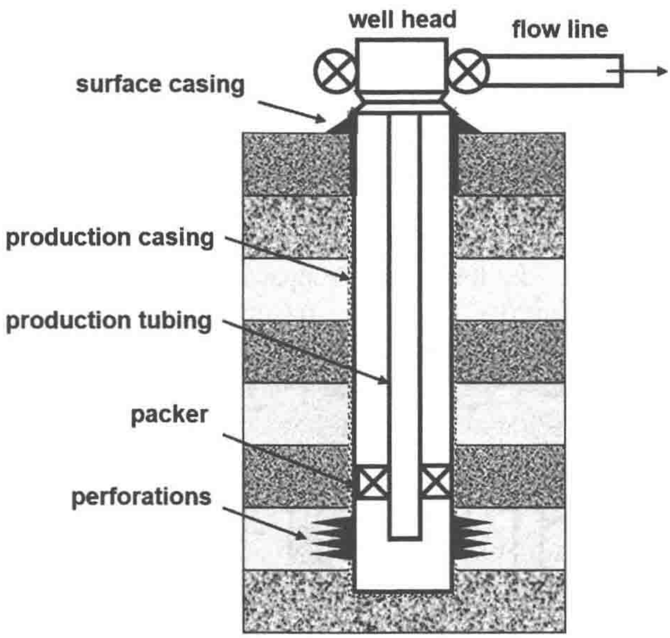



**Figure 1.0.5** Schematic of a producing oil well.

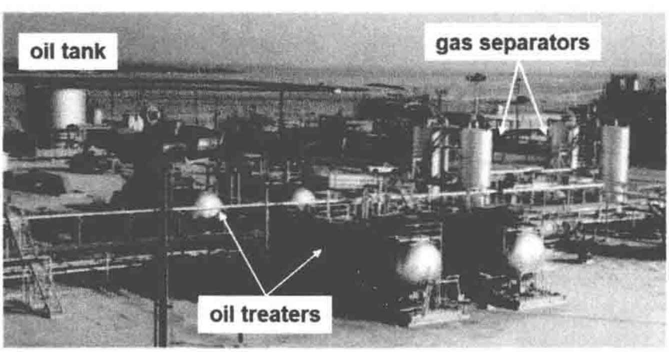



**Figure 1.0.6** Photograph of a large oil battery in Kuwait. http://www.en-fabinc.com/en/gathering.shtml, 2012.

## 1.1 Overview of Reservoir Engineering

Petroleum reservoirs and their associated wells and facilities make up the assets of petroleum-producing companies. The main objective of a petroleum-producing company is to increase the value of its petroleum reservoirs for its stakeholders. The value of a petroleum reservoir depends on several factors: the amount of petroleum in the reservoir; the amount that can be produced; how rapidly the petroleum can be produced; the capital and operating costs involved in recovering the petroleum; royalties and taxes; and the price paid for the petroleum. Petroleum assets can also be discovered, acquired, or sold to increase the value of the company. A petroleum producer usually attempts to maximize its value in all of these areas and to do so calls on various disciplines, including land management, geophysics, geology, engineering, economics, marketing, and accounting.

Roughly speaking, geologists, geophysicists, and petrophysicists describe rock properties and reservoir structure. Production engineers manage wells and surface facilities. Reservoir engineers manage the reservoir. The objective of a reservoir engineer is to produce as much of the petroleum in the reservoir as possible, as quickly as possible, and at the lowest cost, but at the same time maximize economic value. In other words, the role of the reservoir engineer is to determine the maximum amount of petroleum that can be recovered economically, the optimum production rate under existing operations, and the applicability of waterflooding, gas flooding, or enhanced oil recovery (EOR) for the reservoir.

### *1.1.1 Estimation of Volumes in Place, Reserves, and Rates of Recovery*

There is an important distinction to be made between the hydrocarbon in the reservoir (original oil in place and original gas in place, or OOIP and OGIP) and the recoverable hydrocarbon (oil and gas reserves). OOIP and OGIP are what nature provides, while the reserves are what we can economically extract from the reservoir. The OOIP and OGIP partially dictate what recovery schemes can be used and how much of those reserves can be recovered. The ratio of reserves to hydrocarbon in place is defined as the recovery factor.

Two general methods can be used to predict oil in place volumes:

- Volumetrics,
- Material balance.

Five general forecasting methods can be used to determine recoverable volumes (reserves) and production rates:

- Analogy,
- Decline analysis,
- Data mining,
- Analytical,
- Simulation.

*Hydrocarbons-in-place*

The first step is to determine how much petroleum is in the reservoir. The reservoir can be thought of as a packed bed that is full of fluid at high pressure. To determine the amount of fluid in the bed, it is necessary to determine the volume of the bed and the porosity of the bed, that is, the fractional pore space. In the case of reservoir rock, there is a film of water on the rock. This initial water saturation (the fractional volume of the water) must be accounted for. Also, as oil is withdrawn from the bed and produced to the surface, its pressure and temperature decreases to approximately atmospheric pressure and surface temperature. Hence, the relationship among the fluid volume, pressure, and temperature (PVT) must be determined. Any phase changes that may occur as the pressure changes must also be accounted for. For example, does the oil enter a two-phase region and evolve gas? The data required to determine the volume of petroleum in the reservoir include:

- Reservoir volume,
- Reservoir porosity,
- Reservoir water saturation,
- Fluid properties (PVT relationships).

The volume of petroleum determined using this approach is the volumetric OOIP or OGIP. The method of estimating volumetric reserves is essentially the same for all reservoirs. However, reservoir properties are not uniformly distributed. Therefore, both empirical methods and simulation methods may break down. The understanding of reservoir heterogeneity is one the largest challenges reservoir engineers and geoscientists face.

A second method to estimate in-place volumes is to perform a material balance on the reservoir. As fluids are withdrawn, the reservoir pressure declines. The volume of oil, gas, and water initially present in the reservoir can be determined from the extent of pressure decrease for a given fluid withdrawal. The required data are:

- Fluid properties (density, viscosity, PVT relationships),
- Production and injection rates over time,
- Reservoir pressure over time.

The form of the material balance depends on the drive mechanism of reservoir (discussed later). The volume of petroleum determined with this method is the material balance OOIP or OGIP. As a rule of thumb, approximately 10% depletion of the original reservoir pressure is required to use this method with accuracy. In general, the material balance method works well in reservoirs with high permeability or transmissibility, because the reservoir pressure over a reservoir scale tends to equilibrate. Material balances usually work best in higher permeability gas fields (>1 mD). A second constraint of using material balance is the availability and quality of measured pressure data.

Often reservoirs are not closed systems, and an aquifer model is required to complete the material balance. These models relate aquifer influx to aquifer size, pressure, and rock and fluid properties. Aquifer models are often used in water-drive reservoirs in which water influx may provide a significant portion of the energy of the system (>10% of the total drive energy in the system). Generally, there is little information on aquifer parameters because companies usually do not target wells in an aquifer.

A recovery factor is required to convert oil-in-place or gas-in-place values (volumetric and material balance reserves) to recoverable reserves for a particular reservoir. This brings us to the second step, forecasting production and determining the recovery factor.

*Recovery factors*

The analogy method is used most often when there is little production history for the pool of interest. An analogous reservoir is a reservoir with similar rock and fluid properties, geological characteristics, and drive mechanism, but with a more extensive production history. A representative well and/or pool forecast is determined for an analogous reservoir, and a recovery factor is calculated. The forecast and recovery factor are then applied to the reservoir of interest.

The most commonly used method to estimate recoverable reserves is decline analysis. For example, in North America, more than 95% of the small pools have their reserves calculated using decline methods. Decline analysis is simply the extrapolation of existing trends in the production data. In some cases, there is a stronger theoretical basis for the decline trend, such as homogeneous gas reservoirs or oil reservoirs in single-phase flow (Petroleum Society of the Canadian Institute of Mining, Metallurgy and Petroleum, 1994; Araya and Ozkan, 2002; Arps, 1945; Hale, 1986; Camacho-Velazquez and Raghavan, 1989; Masoner, 1998; van Poollen, 1966). Generally, for oil reservoirs that have multiple phases flowing, decline analysis is empirical in nature, but it is still useful as a first estimate of recovery. Often multiphase flow as well as multilayering and heterogeneity can cause complexity and departure from linear trends from decline models.

Another method is to use data-driven models or data mining techniques that correlate injection and production rates by using neutral networks, statistics, or artificial intelligence methods (da Silva et al., 2007; Khazaeni and Mohaghegh, 2011). These techniques can be especially useful in an experienced geoscientist's or engineer's hands. Some production history is required to establish the correlations, and therefore these methods are best suited to mid to late development of a reservoir.

Analytical methods assume certain idealized flow conditions in the reservoir. Analytical models are often useful when reservoir flow is either one- or two–dimensional (2D) in nature. Analytical models can be further classified as:

| | |
|---|---|
| • Radial/linear inflow equations | Relate production/injection rate to pressure gradient, permeability, and fluid properties for horizontal flow field |
| • Coning models | Relate production/injection rate to pressure gradient, permeability, and fluid properties for vertical flow field |
| • Displacement models | Prediction of water flood or gas flood performance from rock and fluid properties |
| • Inflow performance models | Relates bottom-hole flow potential to flow rate |