This book is the second edition of the 1989 book by the name *Enhanced Oil Recovery*. As such, it reflects the substantial changes that have taken place in enhanced oil production technology since that time: from a collection of minor technologies in the early 1980s to a significant and growing portion of the worldwide oil production today.

While it is true that a textbook is out of date the day it is published, there are a couple of ways to head off obsolescence:

First, broaden the topical material. Although the current book is on enhanced oil recovery (EOR), and EOR is not waterflooding, there is substantial coverage on waterflooding, as there is on basic equations, petrophysics, and phase behavior. Indeed, the 1989 book has served as a text for courses (or portions thereof) in numerical simulation, waterflooding, thermodynamics, and petrophysics.

Second, stick to the fundamentals. The fundamentals change slowly if at all, and the current text continues to focus on the basics of material and energy balances, phase behavior, and fractional flow theory.

The target audience remains the same as for the 1989 text: It is a graduate-level textbook whose material is intended to be taught over two long semesters.

So what are the differences with the 1989 text? We have done the following:

- Added example calculations to several of the chapters
- Included explanations of combined condensing and vaporizing displacements in gas floods and their impact on the developed miscible process
- Expanded coverage of foam EOR to an entire chapter
- Added discussion of EOR types, such as steam-assisted gravity drainage and alkaline-surfactant polymer flooding, that were not prominent in 1989
- Deleted coverage of material that did not readily lend itself to classroom instruction (based on many years of classroom experience)
- Added new material on dispersion, decline curves, and the use of so-called Walsh diagrams
- Added material on new technological advances, most notably in the coverage of chemical EOR

The biggest change is that the current text now has four co-authors whose classroom and research expertise in their respective technologies has made the text much stronger than before. It also helps to have four sets of eyes to spot inconsistencies, unclarities, errors, and all around goofs, especially in the equations.

Even with the new version, we are aware of several omissions:

- Low or adjusted salinity water flooding
- Gravity stable surfactant floods
- Hybrid methods such as heated surfactant floods and polymer floods
- Technologies involving in-situ modification of polymers
- Electromagnetic oil recovery
- Seismic oil recovery

These could become glaring omissions depending on future practice. However, we continue to think that reliance on fundamentals—conservation laws, phase behavior, and fractional flow theory—will at least make extension to new methods easier.
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And finally, we dedicate this text to the help and instruction provided by decades of university and short course students. We learn more from you than you from us.
Chapter 1

Defining Enhanced Oil Recovery

Enhanced oil recovery (EOR) is oil recovery by the injection of materials not normally present in petroleum reservoirs. This definition covers all modes of oil-recovery processes (drive, push-pull, and well treatments) and most oil-recovery agents. EOR technologies are also being used for in-situ extraction of organic pollutants from permeable media. In these applications, the extraction is referred to as cleanup or remediation and the pollutant as product. Aspects of these technologies also apply to carbon dioxide (CO₂) storage.

The definition does not restrict EOR to a particular phase (primary, secondary, or tertiary) in the producing life of a reservoir. Primary recovery is oil recovery by natural drive mechanisms: solution gas, water influx, gas-cap drive, or gravity drainage, as illustrated in Fig. 1.1. Secondary recovery refers to techniques, such as gas or water injection, that have the main purpose of boosting or maintaining reservoir pressure. Tertiary recovery is any technique applied after secondary recovery. Nearly all EOR processes have been at least field tested as secondary displacements. Many thermal methods are commercial in both primary and secondary modes. Much interest has been focused on tertiary EOR, but our definition does not impose any such restriction.

A related definition is improved oil recovery, which is EOR plus several technologies that are also intended to increase ultimate oil recovery. Examples of these are hydraulic fracturing, horizontal and multilateral wells, infill drilling, well stimulation, and optimizing the production or injection rates of individual wells.

Definitions of EOR can be important in areas where regulatory agencies give tax or price credits to promote use of EOR. The definition given above is the one used throughout this text.

The definition does exclude waterflooding and is intended to exclude all pressure-maintenance processes. The distinction between pressure maintenance and displacement is fuzzy because displacement occurs in many pressure-maintenance processes. Moreover, agents such as methane in a high-pressure gas drive, or carbon dioxide in a reservoir with substantial native CO₂, do not satisfy the definition, yet both are clearly EOR processes. The same can be said of CO₂ storage. Usually, the EOR cases that fall outside the definition can be clearly classified by the intent of the process.

Fig. 1.1 also shows the major categories of EOR. This text is largely organized around the solvent (Chapter 7), chemical (Chapters 8–10), and thermal (Chapter 11) categories. Although EOR does not include waterflooding, this technology is the mother of all displacement techniques, and some (in fact extensive) coverage is provided in Chapters 3–6. Note that so-called unconventional recovery, or oil and gas recovery from very low-permeability media through fracturing, is part of primary recovery.

Another perspective on the recovery phases is provided in Fig. 1.2. This figure shows oil rate (top in std volumes/time) on the upper plot, pressure (well pressure $P_{wf}$, average reservoir pressure $P$, and injection well pressure $P_{inj}$) on the middle plot, and average oil saturation on the bottom plot, all on a common time axis. The figure is a schematic that treats injection and production as occurring through a single well (in reality, most fields have many wells). The time axis is divided into primary, secondary, and tertiary recovery phases as indicated.
Much depends on the economically limiting rate (labeled EL) and the limiting pressure ($P_{\text{Lim}}$) on the upper and middle plots respectively. EL is the rate at which the revenue from production equals the operating costs of the field. $P_{\text{Lim}}$ is the well pressure below which fluids cannot flow to the surface without external support. Of the two, EL is the most important because it is the portal between the engineering and economic worlds.

Primary production is typically production by fluid expansion and pore-volume contraction caused by pressure decline. In this period, there is no injection and average oil saturation stays roughly constant.
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The rate is characterized by a rapid increase, limited mainly by the rate at which wells are drilled, followed by a plateau period and then a decline. The plateau period ends when the well pressure falls to $P_{\text{lim}}$. The average pressure falls throughout, and primary recovery ends when the drawdown pressure ($\bar{P} - P_{\text{lim}}$) is insufficient to maintain the oil rate above the EL. There is usually little or no water production during primary production. The absence of water production and the prevalence of natural (unassisted) flow usually make this the most profitable phase of the field life.

Secondary production is production by injection of a second fluid, occasionally natural gas, but most commonly water. In this period and throughout the remainder of the field life, the producing well pressure is at $P_{\text{lim}}$ (wells are said to be pumped off), and the average pressure rises. There is a new pressure $P_{\text{inj}}$ for the injection well. Of course we must have $P_{\text{inj}} > \bar{P} > P_{\text{wf}} = P_{\text{lim}}$ to maintain flow. When $\bar{P}$ becomes constant, the pressure is said to be “maintained,” and, of course, production rises because of the increased drawdown.

The increased drawdown, however, causes the injected fluid to be produced, as indicated by the dotted line in the upper plot. An increase in $\bar{P}$ would cause fluids to contract; therefore, production would proceed from this point mainly by displacement. The displacement causes the average oil saturation to decline. Secondary production ends when the rate again approaches the EL, at which point water production can be many times the oil production.

Tertiary production commences when waterflooding becomes uneconomical or when the rate falls below the EL. At this time, chemical agents (surfactants or solvents) or heat are injected that cause physical or chemical changes in the oil. The entire nature of the recovery is based on displacement now, and the pressures change little with time. All the production occurs because of declining average oil saturation.

Several points deserve to be summarized from Fig. 1.2.

1. Production can be increased by lowering $P_{\text{lim}}$ throughout the life of the field. Much oilfield technology is directed to exactly this goal.
2. In the same fashion, production can be increased by increasing the proportionality constant between drawdown and rate, the so-called productivity index (PI) of a producer. Much oilfield technology, including some forms of EOR, is devoted to this.
3. As conditions change, EL need not be constant. Indeed, it is probable that EL will increase during tertiary recovery when agent costs become a principal factor in production. EL is exceptionally sensitive to oil price.
4. The lengths of the periods in the figure are highly variable; usually, primary production occurs over a shorter time than secondary production. The lengths for primary and tertiary production are approximately the same. The total field life can exceed 100 years.
5. Typical ultimate recoveries for primary, secondary, and tertiary recovery are 10%, 25%, and 10% of the original oil in place (OOIP), but with much variation. This gives a typical ultimate recovery of 35% with conventional production. In most cases, the peak waterflood oil rate is less than the primary plateau. The ultimate recoveries are the areas under the rate plot in Fig. 1.2.
6. Remember that the plot in Fig. 1.2 is a schematic. There are many varieties of primary production (Walsh and Lake 2003). For example, sometimes there is no primary plateau. In others, economic conditions do not justify EOR regardless of other favorable factors. Moreover, of course, wells can be added and removed (which is roughly equivalent to changing the PI) throughout the life of the field. For steeply dipping reservoirs, flow potentials should replace pressures in Fig. 1.2.
7. In practice, operations in a reservoir are normally converted or switched before the rate reaches the EL. The switching occurs in anticipation of the time that the rate attains the EL.
8. Although the sequence shown in Fig. 1.2 is typical, sometimes entire phases are missing. As discussed previously, many thermal projects have not undergone primary or even secondary recovery. Furthermore, the times of switching from one phase to another may be different from those shown. Parra-Sanchez (2010) has shown that earlier switching times (i.e., switching from primary to secondary production before reaching the economic limit) can be more profitable.
This text is about the displacement part of the figure, which includes waterflooding and, of course, EOR. Because the pressures are constant during these phases, the fluids behave as though they were incompressible, a fact that justifies the widespread use of this assumption throughout this text. Incompressibility also moves the drawdown pressure and pressure changes to the background in most of our discussion, although it must be remembered that if there is no drawdown, there can be no production.

1.1 Introduction to EOR

1.1.1 The EOR Target. Interest in EOR centers on the amount of oil to which it can be applied. This EOR target oil is the amount that is unrecoverable by conventional means (Fig. 1.1). A large body of statistics shows that conventional ultimate oil recovery (the percentage of the OOIP at the time that further conventional recovery becomes uneconomical) is approximately 35%. This means, for example, that a field that originally contained 1 billion barrels will have 650,000,000 barrels left in it at the end of its conventional life. Considering the OOIP in all the reservoirs in the United States, this value is much larger than targets from exploration or increased drilling.

The ultimate recovery efficiency expected after primary and secondary recovery is shown in Fig. 1.3. This figure also shows that there is enormous variability in ultimate recovery within a single geographic region, which is why we cannot target reservoirs with EOR by region. Fig. 1.3 shows also that the median ultimate recovery is the same for most regions, a fact no doubt bolstered by the large variability within each region. The median ultimate recovery of approximately 35% shows that 65% remains, a significant target for EOR.

1.2 The Need for EOR

Enhanced oil recovery is one of the technologies needed to maintain reserves. What follows is only a brief discussion of reserves because this is a complex and extensive subject. See Cronquist (2001) for more details.

![Box plots of ultimate oil recovery efficiency](image.jpg)

Fig. 1.3—Box plots of ultimate oil recovery efficiency. 75% of the ultimate recoveries in a region fall within the vertical boxes; the median recovery is the horizontal line in the box; the vertical lines give the range. Ultimate recovery is highly variable, but the median is approximately the same everywhere [data from Laherrere (2001); US data from TORIS].
1.2.1 Reserves. One definition of reserves is that they are petroleum (crude and condensate) recoverable from known reservoirs under prevailing economics and technology. They are given by the following material-balance equation:

\[
\begin{pmatrix}
\text{Present reserves} \\
\text{Past reserves}
\end{pmatrix}
= 
\begin{pmatrix}
\text{Additions to reserves} \\
\text{Production from reserves}
\end{pmatrix}
= 
\begin{pmatrix}
\text{Past reserves} \\
\text{Additions to reserves} \\
\text{Production from reserves}
\end{pmatrix}
\]

There are actually several categories of reservoirs (proven, probable, etc.); the distinctions between these are very important to economic evaluation (Rose 2001; Cronquist 2001). Reserves can change with time because the last two terms on the right can change with time. It is in the best interests of producers to maintain reserves constant with time, or even for them to increase.

1.2.2 Adding to Reserves. The four categories of reserve additions are

1. Discovering new fields
2. Discovering new reservoirs
3. Finding more oil in known fields
4. Redefining reserves because of changes in the economics of extraction technology

We discuss Category 4 in the remainder of this text.

EOR is in competition with conventional oil recovery because most producers have assets or access to assets in all the categories in Fig. 1.1. The competition is based largely on economics in addition to reserve replacement. Currently, many EOR technologies are competitive with drilling-based reserve additions. The key to economic competitiveness is how much oil can be recovered with EOR. The estimation of this is the next topic to be discussed.

1.3 Incremental Oil

1.3.1 Definition. A universal technical measure of the success of an EOR process is the amount of incremental oil recovered, or IOR. (We note the possible confusion between IOR as improved oil recovery and IOR as incremental oil recovery. What is meant should be clear from the context of the text. IOR as improved oil recovery is not used further here.) Fig. 1.4 defines the concept of incremental oil. Imagine a field, reservoir, or well in which the oil rate is declining, for example, from A to B. At B, an EOR project is initiated, and, if this is successful, the rate should show a deviation from the projected decline at some time after B. Incremental oil is the difference between what was actually recovered, B to D, and what would have been recovered had the process not been initiated, B to C. Because areas under rate vs. time curves are amounts, this is the shaded region in Fig. 1.4.

As simple as the concept in Fig. 1.4 is, IOR is difficult to determine in practice. There are several reasons for this.

1. Combined (commingled) production from EOR and non-EOR wells. Such production makes it difficult to allocate the EOR-produced oil to the EOR project. Commingling occurs when, as is usually the case, the EOR project is phased into a field undergoing other types of recovery.
2. Oil from other sources. Usually the EOR project has experienced substantial well cleanup or other improvements before startup. The oil produced as a result of such treatment is not easily differentiated from EOR oil.
3. Inaccurate estimate of the hypothetical decline. The curve from B to C in Fig. 1.4 must be estimated accurately. However, because the decline did not occur, there is no way of assessing this accuracy.