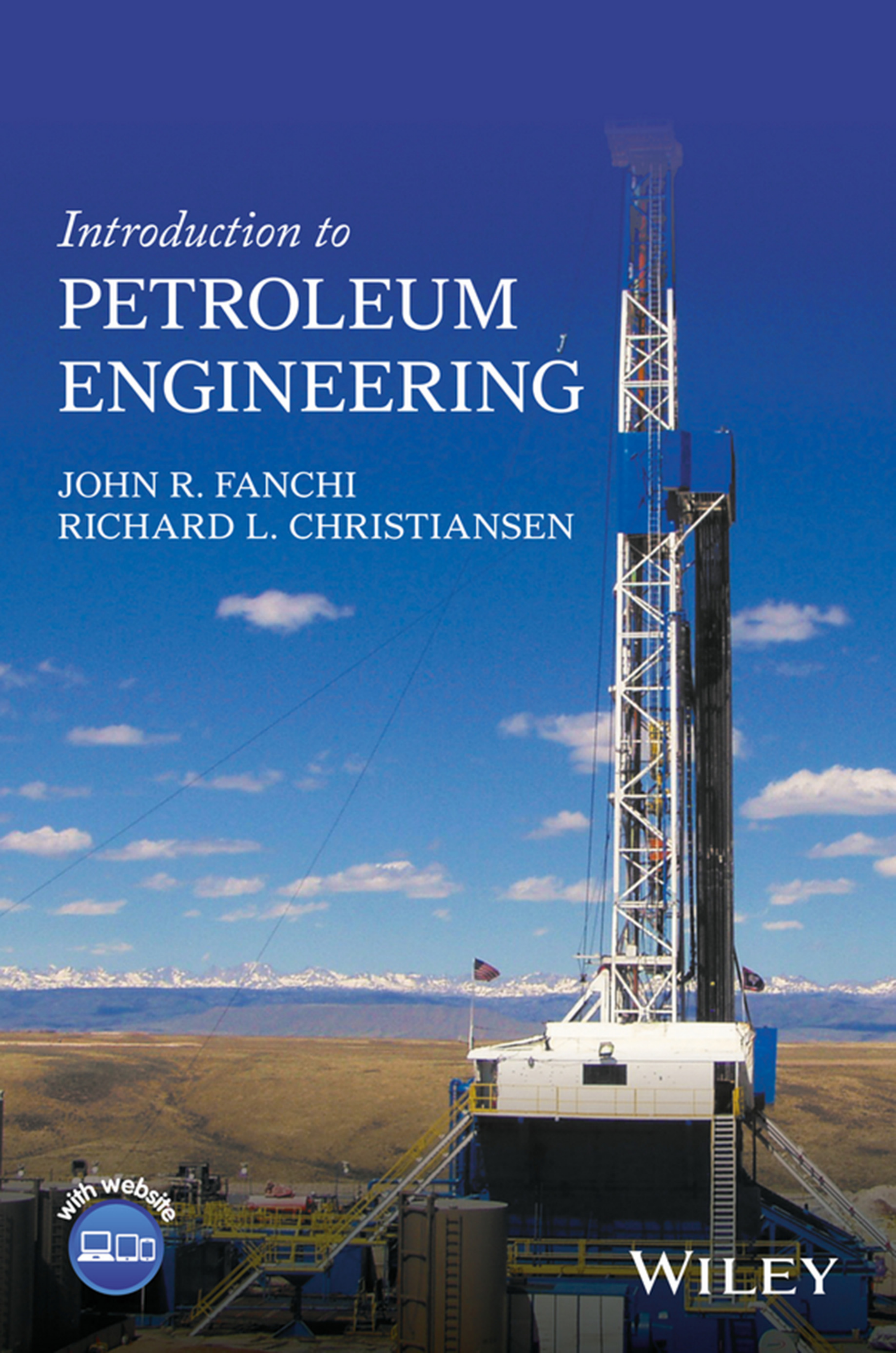
Introduction to PETROLEUM ENGINEERING

JOHN R. FANCHI
RICHARD L. CHRISTIANSEN



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ABOUT THE AUTHORS

John R. Fanchi
John R. Fanchi is a professor in the Department of Engineering and Energy Institute at Texas Christian University in Fort Worth, Texas. He holds the Ross B. Matthews Professorship in Petroleum Engineering and teaches courses in energy and engineering. Before this appointment, he taught petroleum and energy engineering courses at the Colorado School of Mines and worked in the technology centers of four energy companies (Chevron, Marathon, Cities Service, and Getty). He is a Distinguished Member of the Society of Petroleum Engineers and coedited the General Engineering volume of the *Petroleum Engineering Handbook* published by the Society of Petroleum Engineers. He is the author of numerous books, including *Energy in the 21st Century*, 3rd Edition (World Scientific, 2013); *Integrated Reservoir Asset Management* (Elsevier, 2010); *Principles of Applied Reservoir Simulation*, 3rd Edition (Elsevier, 2006); *Math Refresher for Scientists and Engineers*, 3rd Edition (Wiley, 2006); *Energy: Technology and Directions for the Future* (Elsevier-Academic Press, 2004); *Shared Earth Modeling* (Elsevier, 2002); *Integrated Flow Modeling* (Elsevier, 2000); and *Parametrized Relativistic Quantum Theory* (Kluwer, 1993).

Richard L. Christiansen
Richard L. Christiansen is an adjunct professor of chemical engineering at the University of Utah in Salt Lake City. There, he teaches a reservoir engineering course as well as an introductory course for petroleum engineering. Previously, he engaged in all aspects of petroleum engineering as the engineer for a small oil and gas exploration company in Utah. As a member of the Petroleum Engineering faculty at the Colorado School of Mines from 1990 until 2006, he taught a variety of courses, including multiphase flow in wells, flow through porous media, enhanced oil

recovery, and phase behavior. His research experiences include multiphase flow in rock, fractures, and wells; natural gas hydrates; and high-pressure gas flooding. He is the author of *Two-Phase Flow in Porous Media* (2008) that demonstrates fundamentals of relative permeability and capillary pressure. From 1980 to 1990, he worked on high-pressure gas flooding at the technology center for Marathon Oil Company in Colorado. He earned his Ph.D. in chemical engineering at the University of Wisconsin in 1980.

PREFACE

Introduction to Petroleum Engineering introduces people with technical backgrounds to petroleum engineering. The book presents fundamental terminology and concepts from geology, geophysics, petrophysics, drilling, production, and reservoir engineering. It covers upstream, midstream, and downstream operations. Exercises at the end of each chapter are designed to highlight and reinforce material in the chapter and encourage the reader to develop a deeper understanding of the material.

Introduction to Petroleum Engineering is suitable for science and engineering students, practicing scientists and engineers, continuing education classes, industry short courses, or self-study. The material in *Introduction to Petroleum Engineering* has been used in upper-level undergraduate and introductory graduate-level courses for engineering and earth science majors. It is especially useful for geoscientists and mechanical, electrical, environmental, and chemical engineers who would like to learn more about the engineering technology needed to produce oil and gas.

Our colleagues in industry and academia and students in multidisciplinary classes helped us identify material that should be understood by people with a range of technical backgrounds. We thank Helge Alsleben, Bill Eustes, Jim Gilman, Pradeep Kaul, Don Mims, Wayne Pennington, and Rob Sutton for comments on specific chapters and Kathy Fanchi for helping prepare this manuscript.

John R. Fanchi, Ph.D.
Richard L. Christiansen, Ph.D.
June 2016

ABOUT THE COMPANION WEBSITE

This book is accompanied by a companion website:

www.wiley.com/go/Fanchi/IntroPetroleumEngineering

The website includes:

- Solution manual for instructors only

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INTRODUCTION

The global economy is based on an infrastructure that depends on the consumption of petroleum (Fanchi and Fanchi, 2016). Petroleum is a mixture of hydrocarbon molecules and inorganic impurities that can exist in the solid, liquid (oil), or gas phase. Our purpose here is to introduce you to the terminology and techniques used in petroleum engineering. Petroleum engineering is concerned with the production of petroleum from subsurface reservoirs. This chapter describes the role of petroleum engineering in the production of oil and gas and provides a view of oil and gas production from the perspective of a decision maker.

1.1 WHAT IS PETROLEUM ENGINEERING?

A typical workflow for designing, implementing, and executing a project to produce hydrocarbons must fulfill several functions. The workflow must make it possible to identify project opportunities; generate and evaluate alternatives; select and design the desired alternative; implement the alternative; operate the alternative over the life of the project, including abandonment; and then evaluate the success of the project so lessons can be learned and applied to future projects. People with skills from many disciplines are involved in the workflow. For example, petroleum geologists and geophysicists use technology to provide a description of hydrocarbon-bearing reservoir rock (Raymond and Leffler, 2006; Hyne, 2012). Petroleum engineers acquire and apply knowledge of the behavior of oil, water, and gas in porous rock to extract hydrocarbons.

Introduction to Petroleum Engineering, First Edition. John R. Fanchi and Richard L. Christiansen.

Companion website: www.wiley.com/go/Fanchi/IntroPetroleumEngineering

Some companies form asset management teams composed of people with different backgrounds. The asset management team is assigned primary responsibility for developing and implementing a particular project.

Figure 1.1 illustrates a hydrocarbon production system as a collection of subsystems. Oil, gas, and water are contained in the pore space of reservoir rock. The accumulation of hydrocarbons in rock is a reservoir. Reservoir fluids include the fluids originally contained in the reservoir as well as fluids that may be introduced as part of the reservoir management program. Wells are needed to extract fluids from the reservoir. Each well must be drilled and completed so that fluids can flow from the reservoir to the surface. Well performance in the reservoir depends on the properties of the reservoir rock, the interaction between the rock and fluids, and fluid properties. Well performance also depends on several other properties such as the properties of the fluid flowing through the well; the well length, cross section, and trajectory; and type of completion. The connection between the well and the reservoir is achieved by completing the well so fluid can flow from reservoir rock into the well.

Surface equipment is used to drill, complete, and operate wells. Drilling rigs may be permanently installed or portable. Portable drilling rigs can be moved by vehicles that include trucks, barges, ships, or mobile platforms. Separators are used to separate produced fluids into different phases for transport to storage and processing facilities. Transportation of produced fluids occurs by such means as pipelines, tanker trucks, double-hulled tankers, and liquefied natural gas transport ships. Produced hydrocarbons must be processed into marketable products. Processing typically begins near the well site and continues at refineries. Refined hydrocarbons are used for a variety of purposes, such as natural gas for utilities, gasoline and diesel fuel for transportation, and asphalt for paving.

Petroleum engineers are expected to work in environments ranging from desert climates in the Middle East, stormy offshore environments in the North Sea, and

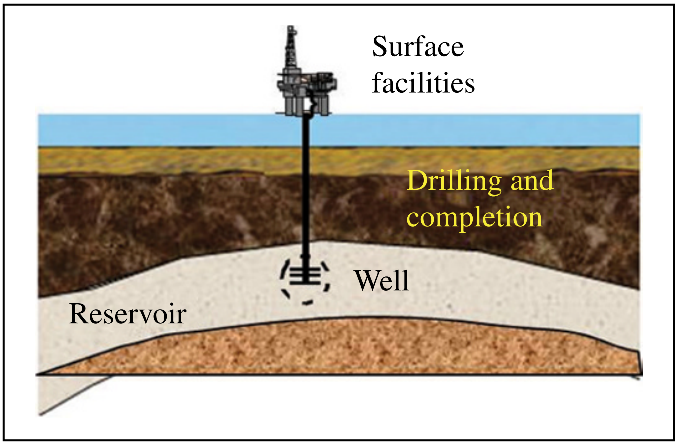

FIGURE 1.1 Production system.

arctic climates in Alaska and Siberia to deepwater environments in the Gulf of Mexico and off the coast of West Africa. They tend to specialize in one of three subdisciplines: drilling engineering, production engineering, and reservoir engineering. Drilling engineers are responsible for drilling and completing wells. Production engineers manage fluid flow between the reservoir and the well. Reservoir engineers seek to optimize hydrocarbon production using an understanding of fluid flow in the reservoir, well placement, well rates, and recovery techniques. The Society of Petroleum Engineers (SPE) is the largest professional society for petroleum engineers. A key function of the society is to disseminate information about the industry.

1.1.1 Alternative Energy Opportunities

Petroleum engineering principles can be applied to subsurface resources other than oil and gas (Fanchi, 2010). Examples include geothermal energy, geologic sequestration of gas, and compressed air energy storage (CAES). Geothermal energy can be obtained from temperature gradients between the shallow ground and surface, subsurface hot water, hot rock several kilometers below the Earth's surface, and magma. Geologic sequestration is the capture, separation, and long-term storage of greenhouse gases or other gas pollutants in a subsurface environment such as a reservoir, aquifer, or coal seam. CAES is an example of a large-scale energy storage technology that is designed to transfer off-peak energy from primary power plants to peak demand periods. The Huntorf CAES facility in Germany and the McIntosh CAES facility in Alabama store gas in salt caverns. Off-peak energy is used to pump air underground and compress it in a salt cavern. The compressed air is produced during periods of peak energy demand to drive a turbine and generate additional electrical power.

1.1.2 Oil and Gas Units

Two sets of units are commonly found in the petroleum literature: oil field units and metric units (SI units). Units used in the text are typically oil field units (Table 1.1). The process of converting from one set of units to another is simplified by providing frequently used factors for converting between oil field units and SI (metric) units in Appendix A. The ability to convert between oil field and SI units is an essential skill because both systems of units are frequently used.

TABLE 1.1 Examples of Common Unit Systems

Property	Oil Field	SI (Metric)	British
Length	ft	m	ft
Time	hr	sec	sec
Pressure	psia	Pa	lbf/ft^2
Volumetric flow rate	bbl/day	m^3/s	ft^3/s
Viscosity	cp	Pa·s	$lbf{\cdot}s/ft^2$

1.1.3 Production Performance Ratios

The ratio of one produced fluid phase to another provides useful information for understanding the dynamic behavior of a reservoir. Let q_o, q_w, q_g be oil, water, and gas production rates, respectively. These production rates are used to calculate the following produced fluid ratios:

Gas–oil ratio (GOR)

$$GOR = \frac{q_g}{q_o} \tag{1.1}$$

Gas–water ratio (GWR)

$$GWR = \frac{q_g}{q_w} \tag{1.2}$$

Water–oil ratio (WOR)

$$WOR = \frac{q_w}{q_o} \tag{1.3}$$

One more produced fluid ratio is water cut, which is water production rate divided by the sum of oil and water production rates:

$$WCT = \frac{q_w}{(q_o + q_w)} \tag{1.4}$$

Water cut (WCT) is a fraction, while WOR can be greater than 1.

Separator GOR is the ratio of gas rate to oil rate. It can be used to indicate fluid type. A separator is a piece of equipment that is used to separate fluid from the well into oil, water, and gas phases. Separator GOR is often expressed as MSCFG/STBO where MSCFG refers to one thousand standard cubic feet of gas and STBO refers to a stock tank barrel of oil. A stock tank is a tank that is used to store produced oil.

Example 1.1 Gas–oil Ratio

A well produces 500 MSCF gas/day and 400 STB oil/day. What is the GOR in MSCFG/STBO?

Answer

$$GOR = \frac{500 \text{ MSCFG/day}}{400 \text{ STBO/day}} = 1.25 \text{ MSCFG/STBO}$$

1.1.4 Classification of Oil and Gas

Surface temperature and pressure are usually less than reservoir temperature and pressure. Hydrocarbon fluids that exist in a single phase at reservoir temperature and pressure often transition to two phases when they are produced to the surface

TABLE 1.2 Rules of Thumb for Classifying Fluid Types

Fluid Type	Separator GOR (MSCF/STB)	Gravity (°API)	Behavior in Reservoir due to Pressure Decrease
Dry gas	No surface liquids		Remains gas
Wet gas	>50	40–60	Remains gas
Condensate	3.3–50	40–60	Gas with liquid dropout
Volatile oil	2.0–3.3	>40	Liquid with significant gas
Black oil	<2.0	<45	Liquid with some gas
Heavy oil	≈0		Negligible gas formation

Data from Raymond and Leffler (2006).

where the temperature and pressure are lower. There are a variety of terms for describing hydrocarbon fluids at surface conditions. Natural gas is a hydrocarbon mixture in the gaseous state at surface conditions. Crude oil is a hydrocarbon mixture in the liquid state at surface conditions. Heavy oils do not contain much gas in solution at reservoir conditions and have a relatively large molecular weight. By contrast, light oils typically contain a large amount of gas in solution at reservoir conditions and have a relatively small molecular weight.

A summary of hydrocarbon fluid types is given in Table 1.2. API gravity in the table is defined in terms of oil specific gravity as

$$\text{API} = \left(\frac{141.5}{\gamma_o}\right) - 131.5 \quad (1.5)$$

The specific gravity of oil is the ratio of oil density ρ_o to freshwater density ρ_w:

$$\gamma_o = \frac{\rho_o}{\rho_w} \quad (1.6)$$

The API gravity of freshwater is 10°API, which is expressed as 10 degrees API. API denotes American Petroleum Institute.

Example 1.2 API Gravity

The specific gravity of an oil sample is 0.85. What is its API gravity?

Answer

$$\text{API gravity} = \frac{141.5}{\gamma_o} - 131.5 = \frac{141.5}{0.85} - 131.5 = 35°\text{API}$$

Another way to classify hydrocarbon liquids is to compare the properties of the hydrocarbon liquid to water. Two key properties are viscosity and density. Viscosity is a measure of the ability to flow, and density is the amount of material in a given volume.

TABLE 1.3 Classifying Hydrocarbon Liquid Types Using API Gravity and Viscosity

Liquid Type	API Gravity (°API)	Viscosity (cp)
Light oil	>31.1	
Medium oil	22.3–31.1	
Heavy oil	10–22.3	
Water	10	1 cp
Extra heavy oil	4–10	<10 000 cp
Bitumen	4–10	>10 000 cp

Water viscosity is 1 cp (centipoise) and water density is 1 g/cc (gram per cubic centimeter) at 60°F. A liquid with smaller viscosity than water flows more easily than water. Gas viscosity is much less than water viscosity. Tar, on the other hand, has very high viscosity relative to water.

Table 1.3 shows a hydrocarbon liquid classification scheme using API gravity and viscosity. Water properties are included in the table for comparison. Bitumen is a hydrocarbon mixture with large molecules and high viscosity. Light oil, medium oil, and heavy oil are different types of crude oil and are less dense than water. Extra heavy oil and bitumen are denser than water. In general, crude oil will float on water, while extra heavy oil and bitumen will sink in water.

1.2 LIFE CYCLE OF A RESERVOIR

The life cycle of a reservoir begins when the field becomes an exploration prospect and does not end until the field is properly abandoned. An exploration prospect is a geological structure that may contain hydrocarbons. The exploration stage of the project begins when resources are allocated to identify and assess a prospect for possible development. This stage may require the acquisition and analysis of more data before an exploration well is drilled. Exploratory wells are also referred to as wildcats. They can be used to test a trap that has never produced, test a new reservoir in a known field, and extend the known limits of a producing reservoir. Discovery occurs when an exploration well is drilled and hydrocarbons are encountered.

Figure 1.2 illustrates a typical production profile for an oil field beginning with the discovery well and proceeding to abandonment. Production can begin immediately after the discovery well is drilled or several years later after appraisal and delineation wells have been drilled. Appraisal wells are used to provide more information about reservoir properties and fluid flow. Delineation wells better define reservoir boundaries. In some cases, delineation wells are converted to development wells. Development wells are drilled in the known extent of the field and are used to optimize resource recovery. A buildup period ensues after first oil until a production plateau is reached. The production plateau is usually a consequence of facility limitations such as pipeline capacity. A production decline will eventually occur. Production continues until an economic limit is reached and the field is abandoned.

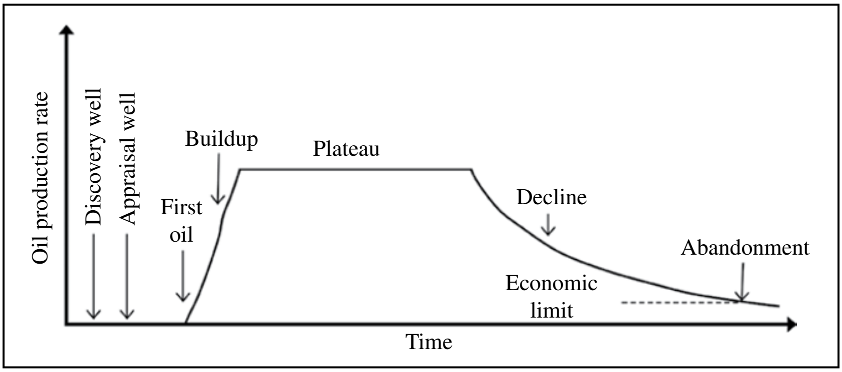

FIGURE 1.2 Typical production profile.

Petroleum engineers provide input to decision makers in management to help determine suitable optimization criteria. The optimization criteria are expected to abide by government regulations. Fields produced over a period of years or decades may be operated using optimization criteria that change during the life of the reservoir. Changes in optimization criteria occur for a variety of reason, including changes in technology, changes in economic factors, and the analysis of new information obtained during earlier stages of production.

Traditionally, production stages were identified by chronological order as primary, secondary, and tertiary production. Primary production is the first stage of production and relies entirely on natural energy sources to drive reservoir fluids to the production well. The reduction of pressure during primary production is often referred to as primary depletion. Oil recovery can be increased in many cases by slowing the decline in pressure. This can be achieved by supplementing natural reservoir energy. The supplemental energy is provided using an external energy source, such as water injection or gas injection. The injection of water or natural gas may be referred to as pressure maintenance or secondary production. Pressure maintenance is often introduced early in the production life of some modern reservoirs. In this case the reservoir is not subjected to a conventional primary production phase.

Historically, primary production was followed by secondary production and then tertiary production (Figure 1.3). Notice that the production plateau shown in Figure 1.2 does not have to appear if all of the production can be handled by surface facilities. Secondary production occurs after primary production and includes the injection of a fluid such as water or gas. The injection of water is referred to as water flooding, while the injection of a gas is called gas flooding. Typical injection gases include methane, carbon dioxide, or nitrogen. Gas flooding is considered a secondary production process if the gas is injected at a pressure that is too low to allow the injected gas to be miscible with the oil phase. A miscible process occurs when the gas injection pressure is high enough that the interface between gas and oil phases disappears. In the miscible case, injected gas mixes with oil and the process is considered an enhanced oil recovery (EOR) process.

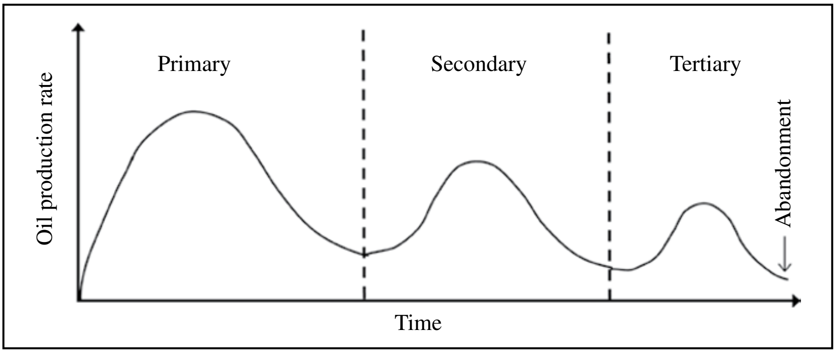

FIGURE 1.3 Sketch of production stages.

EOR processes include miscible, chemical, thermal, and microbial processes. Miscible processes inject gases that can mix with oil at sufficiently high pressures and temperatures. Chemical processes use the injection of chemicals such as polymers and surfactants to increase oil recovery. Thermal processes add heat to the reservoir. This is achieved by injecting heated fluids such as steam or hot water or by the injection of oxygen-containing air into the reservoir and then burning the oil as a combustion process. The additional heat reduces the viscosity of the oil and increases the mobility of the oil. Microbial processes use microbe injection to reduce the size of high molecular weight hydrocarbons and improve oil mobility. EOR processes were originally implemented as a third, or tertiary, production stage that followed secondary production.

EOR processes are designed to improve displacement efficiency by injecting fluids or heat. The analysis of results from laboratory experiments and field applications showed that some fields would perform better if the EOR process was implemented before the third stage in field life. In addition, it was found that EOR processes were often more expensive than just drilling more wells in a denser pattern. The process of increasing the density of wells in an area is known as infill drilling. The term improved oil recovery (IOR) includes EOR and infill drilling for improving the recovery of oil. The addition of wells to a field during infill drilling can also increase the rate of withdrawal of hydrocarbons in a process known as acceleration of production.

Several mechanisms can occur during the production process. For example, production mechanisms that occur during primary production depend on such factors as reservoir structure, pressure, temperature, and fluid type. Production of fluids without injecting other fluids will cause a reduction of reservoir pressure. The reduction in pressure can result in expansion of *in situ* fluids. In some cases, the reduction in pressure is ameliorated if water moves in to replace the produced hydrocarbons. Many reservoirs are in contact with water-bearing formations called aquifers. If the aquifer is much larger than the reservoir and is able to flow into the reservoir with relative ease, the reduction in pressure in the reservoir due to hydrocarbon production will be much less that hydrocarbon production from a reservoir that is not receiving support from an aquifer. The natural forces involved in primary production are called reservoir drives and are discussed in more detail in a later chapter.

Example 1.3 Gas Recovery

The original gas in place (OGIP) of a gas reservoir is 5 trillion ft^3 (TCF). How much gas can be recovered (in TCF) if recovery from analogous fields is between 70 and 90% of OGIP?

Answer
Two estimates are possible: a lower estimate and an upper estimate.
The lower estimate of gas recovery is 0.70×5 TCF = 3.5 TCF.
The upper estimate of gas recovery is 0.90×5 TCF = 4.5 TCF.

1.3 RESERVOIR MANAGEMENT

One definition of reservoir management says that the primary objective of reservoir management is to determine the optimum operating conditions needed to maximize the economic recovery of a subsurface resource. This is achieved by using available resources to accomplish two competing objectives: optimizing recovery from a reservoir while simultaneously minimizing capital investments and operating expenses. As an example, consider the development of an oil reservoir. It is possible to maximize recovery from the reservoir by drilling a large number of wells, but the cost would be excessive. On the other hand, drilling a single well would provide some of the oil but would make it very difficult to recover a significant fraction of the oil in a reasonable time frame. Reservoir management is a process for balancing competing objectives to achieve the key objective.

An alternate definition (Saleri, 2002) says that reservoir management is a continuous process designed to optimize the interaction between data and decision making. Both definitions describe a dynamic process that is intended to integrate information from multiple disciplines to optimize reservoir performance. The process should recognize uncertainty resulting from our inability to completely characterize the reservoir and fluid flow processes. The reservoir management definitions given earlier can be interpreted to cover the management of hydrocarbon reservoirs as well as other reservoir systems. For example, a geothermal reservoir is essentially operated by producing fluid from a geological formation. The management of the geothermal reservoir is a reservoir management task.

It may be necessary to modify a reservoir management plan based on new information obtained during the life of the reservoir. A plan should be flexible enough to accommodate changes in economic, technological, and environmental factors. Furthermore, the plan is expected to address all relevant operating issues, including governmental regulations. Reservoir management plans are developed using input from many disciplines, as we see in later chapters.

1.3.1 Recovery Efficiency

An important objective of reservoir management is to optimize recovery from a resource. The amount of resource recovered relative to the amount of resource originally in place is defined by comparing initial and final *in situ* fluid volumes.

The ratio of fluid volume remaining in the reservoir after production to the fluid volume originally in place is recovery efficiency. Recovery efficiency can be expressed as a fraction or a percentage. An estimate of recovery efficiency is obtained by considering the factors that contribute to the recovery of a subsurface fluid: displacement efficiency and volumetric sweep efficiency.

Displacement efficiency E_D is a measure of the amount of fluid in the system that can be mobilized by a displacement process. For example, water can displace oil in a core. Displacement efficiency is the difference between oil volume at initial conditions and oil volume at final (abandonment) conditions divided by the oil volume at initial conditions:

$$E_{\mathrm{D}} = \frac{\left(S_{\mathrm{oi}}/B_{\mathrm{oi}}\right) - \left(S_{\mathrm{oa}}/B_{\mathrm{oa}}\right)}{S_{\mathrm{oi}}/B_{\mathrm{oi}}} \tag{1.7}$$

where S_{oi} is initial oil saturation and S_{oa} is oil saturation at abandonment. Oil saturation is the fraction of oil occupying the volume in a pore space. Abandonment refers to the time when the process is completed. Formation volume factor (FVF) is the volume occupied by a fluid at reservoir conditions divided by the volume occupied by the fluid at standard conditions. The terms B_{oi} and B_{oa} refer to FVF initially and at abandonment, respectively.

Example 1.4 Formation Volume Factor

Suppose oil occupies 1 bbl at stock tank (surface) conditions and 1.4 bbl at reservoir conditions. The oil volume at reservoir conditions is larger because gas is dissolved in the liquid oil. What is the FVF of the oil?

Answer

$$\text{Oil FVF} = \frac{\text{vol at reservoir conditions}}{\text{vol at surface conditions}}$$

$$\text{Oil FVF} = \frac{1.4\,\text{RB}}{1.0\,\text{STB}} = 1.4\,\text{RB/STB}$$

Volumetric sweep efficiency E_{Vol} expresses the efficiency of fluid recovery from a reservoir volume. It can be written as the product of areal sweep efficiency and vertical sweep efficiency:

$$E_{\mathrm{Vol}} = E_{\mathrm{A}} \times E_{\mathrm{V}} \tag{1.8}$$

Areal sweep efficiency E_A and vertical sweep efficiency E_V represent the efficiencies associated with the displacement of one fluid by another in the areal plane and vertical dimension. They represent the contact between *in situ* and injected fluids. Areal sweep efficiency is defined as

$$E_{\mathrm{A}} = \frac{\text{swept area}}{\text{total area}} \tag{1.9}$$

and vertical sweep efficiency is defined as

$$E_V = \frac{\text{swept net thickness}}{\text{total net thickness}} \tag{1.10}$$

Recovery efficiency RE is the product of displacement efficiency and volumetric sweep efficiency:

$$\text{RE} = E_D \times E_{Vol} = E_D \times E_A \times E_V \tag{1.11}$$

Displacement efficiency, areal sweep efficiency, vertical sweep efficiency, and recovery efficiency are fractions that vary from 0 to 1. Each of the efficiencies that contribute to recovery efficiency can be relatively large and still yield a recovery efficiency that is relatively small. Reservoir management often focuses on finding the efficiency factor that can be improved by the application of technology.

Example 1.5 Recovery Efficiency

Calculate volumetric sweep efficiency E_{Vol} and recovery efficiency RE from the following data:

S_{oi}	0.75
S_{oa}	0.30
Area swept	750 acres
Total area	1000 acres
Thickness swept	10 ft
Total thickness	15 ft
Neglect FVF effects since $B_{oi} \approx B_{oa}$	

Answer

Displacement efficiency: $$E_D = \frac{(S_{oi}/B_{oi}) - (S_{oa}/B_{oa})}{S_{oi}/B_{oi}} \approx \frac{S_{oi} - S_{oa}}{S_{oi}} = 0.6$$

Areal sweep efficiency: $$E_A = \frac{\text{swept area}}{\text{total area}} = 0.75$$

Vertical sweep efficiency: $$E_V = \frac{\text{swept net thickness}}{\text{total net thickness}} = 0.667$$

Volumetric sweep efficiency: $$E_{vol} = E_A \times E_V = 0.5$$

Recovery efficiency: $$\text{RE} = E_D \times E_{Vol} = 0.3$$

1.4 PETROLEUM ECONOMICS

The decision to develop a petroleum reservoir is a business decision that requires an analysis of project economics. A prediction of cash flow from a project is obtained by combining a prediction of fluid production volume with a forecast of fluid price.

Production volume is predicted using engineering calculations, while fluid price estimates are obtained using economic models. The calculation of cash flow for different scenarios can be used to compare the economic value of competing reservoir development concepts.

Cash flow is an example of an economic measure of investment worth. Economic measures have several characteristics. An economic measure should be consistent with the goals of the organization. It should be easy to understand and apply so that it can be used for cost-effective decision making. Economic measures that can be quantified permit alternatives to be compared and ranked.

Net present value (NPV) is an economic measure that is typically used to evaluate cash flow associated with reservoir performance. NPV is the difference between the present value of revenue R and the present value of expenses E:

$$\mathrm{NPV} = R - E \tag{1.12}$$

The time value of money is incorporated into NPV using discount rate r. The value of money is adjusted to the value associated with a base year using discount rate. Cash flow calculated using a discount rate is called discounted cash flow. As an example, NPV for an oil and/or gas reservoir may be calculated for a specified discount rate by taking the difference between revenue and expenses (Fanchi, 2010):

$$\begin{aligned}\mathrm{NPV} &= \sum_{n=1}^{N} \frac{P_{\mathrm{on}} q_{\mathrm{on}} + P_{\mathrm{gn}} q_{\mathrm{gn}}}{(1+r)^n} - \sum_{n=1}^{N} \frac{\mathrm{CAPEX}_n + \mathrm{OPEX}_n + \mathrm{TAX}_n}{(1+r)^n} \\ &= \sum_{n=1}^{N} \frac{P_{\mathrm{on}} q_{\mathrm{on}} + P_{\mathrm{gn}} q_{\mathrm{gn}} - \mathrm{CAPEX}_n - \mathrm{OPEX}_n - \mathrm{TAX}_n}{(1+r)^n}\end{aligned} \tag{1.13}$$

where N is the number of years, P_{on} is oil price during year n, q_{on} is oil production during year n, P_{gn} is gas price during year n, q_{gn} is gas production during year n, CAPEX_n is capital expenses during year n, OPEX_n is operating expenses during year n, TAX_n is taxes during year n, and r is discount rate.

The NPV for a particular case is the value of the cash flow at a specified discount rate. The discount rate at which the maximum NPV is zero is called the discounted cash flow return on investment (DCFROI) or internal rate of return (IRR). DCFROI is useful for comparing different projects.

Figure 1.4 shows a typical plot of NPV as a function of time. The early time part of the figure shows a negative NPV and indicates that the project is operating at a loss. The loss is usually associated with initial capital investments and operating expenses that are incurred before the project begins to generate revenue. The reduction in loss and eventual growth in positive NPV are due to the generation of revenue in excess of expenses. The point in time on the graph where the NPV is zero after the project has begun is the discounted payout time. Discounted payout time on Figure 1.4 is approximately 2.5 years.

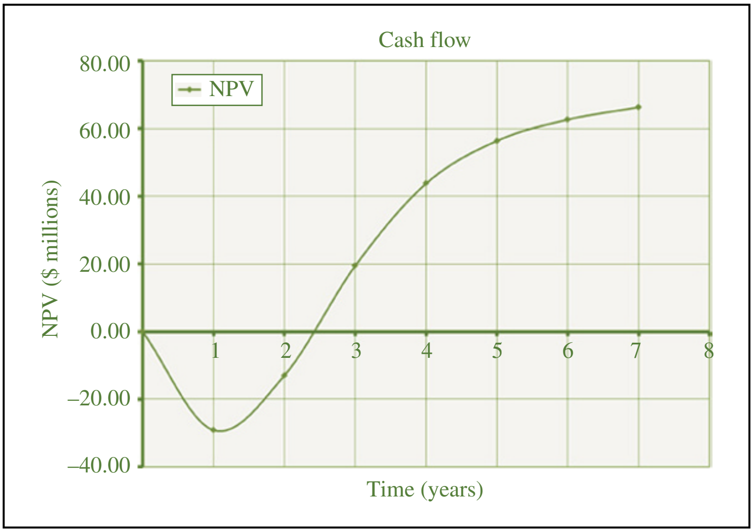

FIGURE 1.4 Typical cash flow.

TABLE 1.4 Definitions of Selected Economic Measures

Economic Measure	Definition
Discount rate	Factor to adjust the value of money to a base year
Net present value (NPV)	Value of cash flow at a specified discount rate
Discounted payout time	Time when NPV = 0
DCFROI or IRR	Discount rate at which maximum NPV = 0
Profit-to-investment (PI) ratio	Undiscounted cash flow without capital investment divided by total investment

Table 1.4 presents the definitions of several commonly used economic measures. DCFROI and discounted payout time are measures of the economic viability of a project. Another measure is the profit-to-investment (PI) ratio which is a measure of profitability. It is defined as the total undiscounted cash flow without capital investment divided by total investment. Unlike the DCFROI, the PI ratio does not take into account the time value of money. Useful plots include a plot of NPV versus time and a plot of NPV versus discount rate.

Production volumes and price forecasts are needed in the NPV calculation. The input data used to prepare forecasts includes data that is not well known. Other possible sources of error exist. For example, the forecast calculation may not adequately represent the behavior of the system throughout the duration of the forecast, or a geopolitical event could change global economics. It is possible to quantify uncertainty by making reasonable changes to input data used to calculate forecasts so that a range of NPV results is provided. This process is illustrated in the discussion of decline curve analysis in a later chapter.

1.4.1 The Price of Oil

The price of oil is influenced by geopolitical events. The Arab–Israeli war triggered the first oil crisis in 1973. An oil crisis is an increase in oil price that causes a significant reduction in the productivity of a nation. The effects of the Arab oil embargo were felt immediately. From the beginning of 1973 to the beginning of 1974, the price of a barrel of oil more than doubled. Americans were forced to ration gasoline, with customers lining up at gas stations and accusations of price gouging. The Arab oil embargo prompted nations around the world to begin seriously considering a shift away from a carbon-based economy. Despite these concerns and the occurrence of subsequent oil crises, the world still obtains over 80% of its energy from fossil fuels.

Historically, the price of oil has peaked when geopolitical events threaten or disrupt the supply of oil. Alarmists have made dire predictions in the media that the price of oil will increase with virtually no limit since the first oil crisis in 1973. These predictions neglect market forces that constrain the price of oil and other fossil fuels.

Example 1.6 Oil Security

A. If \$100 billion is spent on the military in a year to protect the delivery of 20 million barrels of oil per day to the global market, how much does the military budget add to the cost of a barrel of oil?

Answer

$$\text{Total oil per year} = (20 \text{ million bbl/day}) \times (365 \text{ days/yr}) = 7.3 \text{ billion bbl/yr}$$

$$\text{Cost of military/bbl} = \frac{\$100 \text{ billion/yr}}{7.3 \text{ billion bbl/yr}} = \$13.70/\text{bbl}$$

B. How much is this cost per gallon?

Answer

$$\text{Cost/gal} = (\$13.70/\text{bbl}) \times (1 \text{ bbl}/42 \text{ gal}) = \$0.33/\text{gal}$$

1.4.2 How Does Oil Price Affect Oil Recovery?

Many experts believe we are running out of oil because it is becoming increasingly difficult to discover new reservoirs that contain large volumes of conventional oil and gas. Much of the exploration effort is focusing on less hospitable climates, such as arctic conditions in Siberia and deepwater offshore regions near West Africa. Yet we already know where large volumes of oil remain: in the reservoirs that have already been discovered and developed. Current development techniques have recovered approximately one third of the oil in known fields. That means roughly two thirds remains in the ground where it was originally found.

TABLE 1.5 Sensitivity of Oil Recovery Technology to Oil Price

	Oil Price Range	
Oil Recovery Technology	1997$/bbl	2016$/bbl 5% Inflation
Conventional	15–25	38–63
Enhanced oil recovery (EOR)	20–40	51–101
Extra heavy oil (e.g., tar sands)	25–45	63–114
Alternative energy sources	40–60	101–152

The efficiency of oil recovery depends on cost. Companies can produce much more oil from existing reservoirs if they are willing to pay for it and if the market will support that cost. Most oil-producing companies choose to seek and produce less expensive oil so they can compete in the international marketplace. Table 1.5 illustrates the sensitivity of oil-producing techniques to the price of oil. Oil prices in the table include prices in the original 1997 prices and inflation adjusted prices to 2016. The actual inflation rate for oil prices depends on a number of factors, such as size and availability of supply and demand.

Table 1.5 shows that more sophisticated technologies can be justified as the price of oil increases. It also includes a price estimate for alternative energy sources, such as wind and solar. Technological advances are helping wind and solar energy become economically competitive with oil and gas as energy sources for generating electricity. In some cases there is overlap between one technology and another. For example, steam flooding is an EOR process that can compete with conventional oil recovery techniques such as water flooding, while chemical flooding is one of the most expensive EOR processes.

1.4.3 How High Can Oil Prices Go?

In addition to relating recovery technology to oil price, Table 1.5 contains another important point: the price of oil will not rise without limit. For the data given in the table, we see that alternative energy sources become cost competitive when the price of oil rises above 2016$101 per barrel. If the price of oil stays at 2016$101 per barrel or higher for an extended period of time, energy consumers will begin to switch to less expensive energy sources. This switch is known as product substitution. The impact of price on consumer behavior is illustrated by consumers in European countries that pay much more for gasoline than consumers in the United States. Countries such as Denmark, Germany, and Holland are rapidly developing wind energy as a substitute to fossil fuels for generating electricity.

Historically, we have seen oil-exporting countries try to maximize their income and minimize competition from alternative energy and expensive oil recovery technologies by supplying just enough oil to keep the price below the price needed to justify product substitution. Saudi Arabia has used an increase in the supply of oil to drive down the cost of oil. This creates problems for organizations that are trying to develop more costly sources of oil, such as shale oil in the United States. It also creates problems for oil-exporting nations that are relying on a relatively high oil price to fund their government spending.

Oil-importing countries can attempt to minimize their dependence on imported oil by developing technologies that reduce the cost of alternative energy. If an oil-importing country contains mature oil reservoirs, the development of relatively inexpensive technologies for producing oil remaining in mature reservoirs or the imposition of economic incentives to encourage domestic oil production can be used to reduce the country's dependence on imported oil.

1.5 PETROLEUM AND THE ENVIRONMENT

Fossil fuels—coal, oil, and natural gas—can harm the environment when they are consumed. Surface mining of coal scars the environment until the land is reclaimed. Oil pollutes everything it touches when it is spilled on land or at sea. Pictures of wildlife covered in oil or natural gas appearing in drinking water have added to the public perception of oil and gas as "dirty" energy sources. The combustion of fossil fuels yields environmentally undesirable by-products. It is tempting to conclude that fossil fuels have always harmed the environment. However, if we look at the history of energy consumption, we see that fossil fuels have a history of helping protect the environment when they were first adopted by society as a major energy source.

Wood was the fuel of choice for most of human history and is still a significant contributor to the global energy portfolio. The growth in demand for wood energy associated with increasing population and technological advancements such as the development of the steam engine raised concerns about deforestation and led to a search for new source of fuel. The discovery of coal, a rock that burned, reduced the demand for wood and helped save the forests.

Coal combustion was used as the primary energy source in industrialized societies prior to 1850. Another fuel, whale oil, was used as an illuminant and joined coal as part of the nineteenth-century energy portfolio. Demand for whale oil motivated the harvesting of whales for their oil and was leading to the extinction of whales. The discovery that rock oil, what we now call crude oil, could also be used as an illuminant provided a product that could be substituted for whale oil if there was enough rock oil to meet growing demand. In 1861, the magazine *Vanity Fair* published a cartoon showing whales at a Grand Ball celebrating the production of oil in Pennsylvania. Improvements in drilling technology and the discovery of oil fields that could provide large volumes of oil at high flow rates made oil less expensive than coal and whale oil. From an environmental perspective, the substitution of rock oil for whale oil saved the whales in the latter half of the nineteenth century. Today, concern about the harmful environmental effects of fossil fuels, especially coal and oil, is motivating a transition to more beneficial sources of energy. The basis for this concern is considered next.

1.5.1 Anthropogenic Climate Change

One environmental concern facing society today is anthropogenic climate change. When a carbon-based fuel burns in air, carbon reacts with oxygen and nitrogen in the air to produce carbon dioxide (CO_2), carbon monoxide, and nitrogen oxides

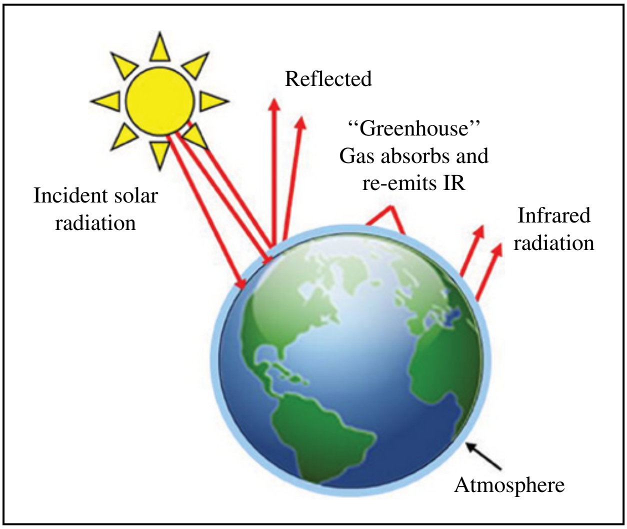

FIGURE 1.5 The greenhouse effect. (Source: Fanchi (2004). Reproduced with permission of Elsevier Academic Press.)

(often abbreviated as NOx). The by-products of unconfined combustion, including water vapor, are emitted into the atmosphere in gaseous form.

Some gaseous combustion by-products are called greenhouse gases because they absorb heat energy. Greenhouse gases include water vapor, carbon dioxide, methane, and nitrous oxide. Greenhouse gas molecules can absorb infrared light. When a greenhouse gas molecule in the atmosphere absorbs infrared light, the energy of the absorbed photon of light is transformed into the kinetic energy of the gas molecule. The associated increase in atmospheric temperature is the greenhouse effect illustrated in Figure 1.5.

Much of the solar energy arriving at the top of the atmosphere does not pass through the atmosphere to the surface of the Earth. A study of the distribution of light energy arriving at the surface of the Earth shows that energy from the sun at certain frequencies (or, equivalently, wavelengths) is absorbed in the atmosphere. Several of the gaps are associated with light absorption by a greenhouse gas molecule.

One way to measure the concentration of greenhouse gases is to measure the concentration of a particular greenhouse gas. Charles David Keeling began measuring atmospheric carbon dioxide concentration at the Mauna Loa Observatory on the Big Island of Hawaii in 1958. Keeling observed a steady increase in carbon dioxide concentration since he began his measurements. His curve, which is now known as the Keeling curve, is shown in Figure 1.6. It exhibits an annual cycle in carbon dioxide concentration overlaying an increasing average. The initial carbon dioxide concentration was measured at a little over 310 parts per million. Today it is approximately 400 parts per million. These measurements show that carbon dioxide concentration in the atmosphere has been increasing since the middle of the twentieth century.