1

Basic Concepts in Reservoir Engineering

1.1 Rocks and Their Types

A rock is a consolidated mixture of minerals. By “consolidated,” we mean hard and strong; real rocks don’t fall apart in your hands! A mixture of minerals implies the presence of more than one mineral grain, but not necessarily more than one type of mineral. For example, a rock can be composed of only one type of mineral, such as limestone, which is commonly made up of only calcite. However, most rocks are composed of several different minerals. Rocks can also include nonminerals, such as fossils or organic matter within a coal bed or in some types of mudstone.

A critical point to remember is the difference between a mineral and a rock. A mineral is a naturally occurring, inorganic solid with a specific chemical composition and a crystalline structure. Minerals are the building blocks of rocks and are defined by their unique physical and chemical properties. Examples of minerals include feldspar, quartz, mica, halite, calcite, and amphibole. These minerals vary in hardness, color, luster, and crystal form, and they are often used to identify and classify different types of rocks.

On the other hand, a rock is typically a mixture of several different minerals. For instance, granite is a common rock composed of quartz, feldspar, and mica. The proportions and types of minerals present in a rock determine its characteristics and classification. Rocks are categorized into three main types based on their formation processes: igneous, sedimentary, and metamorphic.

1. *Igneous rocks*: These rocks form from the cooling and crystallization of magma, which is molten rock beneath the Earth’s surface. When magma cools slowly beneath the Earth’s crust, it forms intrusive igneous rocks such as granite, which have large, visible crystals. Conversely, when magma erupts onto the surface and cools quickly, it forms extrusive igneous rocks such as basalt, which have smaller crystals.
2. *Sedimentary rocks*: These rocks are formed from the accumulation and lithification of sediment. The sediments produced by weathering and erosion are eventually deposited in various environments, such as rivers, lakes, deserts, and oceans.

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Over time, these sediments accumulate in layers and undergo lithification—a process of compaction and cementation—to form sedimentary rocks. Sediments can be fragments of other rocks, mineral grains, or biological materials. Sedimentary rocks are often layered and can contain fossils. Common types include sandstone, formed from compacted sand grains, and limestone, formed primarily from the remains of marine organisms. Sedimentary rocks provide valuable information about Earth's history and past environments.

More than 70% of the area of all continents is covered with sedimentary rocks, and most of the mineral deposits are directly associated with them.

Depending on the forming processes, sedimentary rocks are divided into the following three groups:

- clastic (crushed stone, sand, pebbles, gravel, clay);
- chemical (various salts, silica); and
- organogenic (limestones, fossil fuels).

Common sedimentary rocks include:

- Sandstone: Formed from compacted sand grains.
- Shale: Formed from compacted clay particles.
- Limestone: Formed primarily from the remains of marine organisms.

3. *Metamorphic Rocks*: These rocks form when preexisting igneous or sedimentary rocks are subjected to high temperatures, pressures, or chemically active fluids, causing them to undergo physical and chemical changes, leading to metamorphism. Metamorphic processes can result in the formation of new minerals and the reorganization of mineral grains into a more compact, crystalline structure. Examples of metamorphic rocks include schist, which has a foliated texture, and marble, which forms from limestone.

1.1.1 The Rock Cycle

The rock cycle is a fundamental concept in geology that describes the dynamic transformations of rocks within the Earth's crust. The rock cycle is a continuous process, and rocks can be recycled through the cycle many times from one type to another through various geological processes (Figure 1.1). For example:

- Igneous to Sedimentary: Igneous rocks exposed at the surface are weathered and eroded into sediments, which are then compacted and cemented to form sedimentary rocks.
- Sedimentary to Metamorphic: Sedimentary rocks buried deep within the crust are subjected to heat and pressure, transforming them into metamorphic rocks.
- Metamorphic to Magma: Metamorphic rocks can melt under extreme conditions to become magma, restarting the cycle.

The rock cycle is a vital part of the Earth's system. It helps to recycle the Earth's materials, and it also plays a role in the formation of mineral deposits. The rock cycle is a complex process, but it is essential for understanding the Earth's geology.

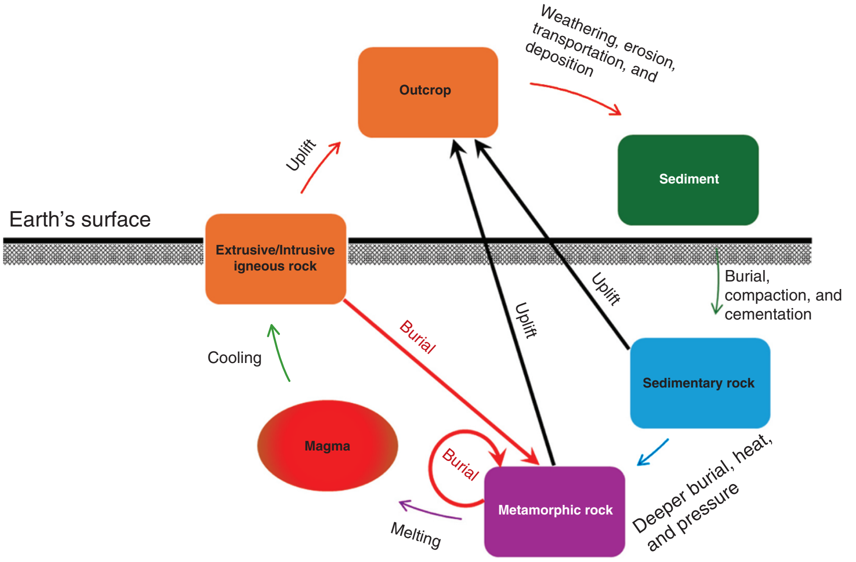


Figure 1.1 Schematics of the rock cycle.

This cycle is driven by two primary forces:

1. *Earth's internal heat engine*: The immense heat from the Earth's interior causes convection currents in the mantle, leading to the movement of tectonic plates. This movement drives processes, such as volcanic activity, mountain building, and the formation of igneous and metamorphic rocks. For example, when tectonic plates collide, they can push rocks deep into the Earth's crust, where they are subjected to high temperatures and pressures, forming metamorphic rocks (Figure 1.2).
2. *The hydrological cycle*: Powered by solar energy, the hydrological cycle involves the continuous movement of water on, above, and below the surface of the Earth. This cycle includes processes, such as weathering, erosion, transportation, deposition, and precipitation (Figure 1.3). For instance, rainwater can cause the weathering of rocks, breaking them down into smaller particles that are transported by rivers and deposited as sediment in lakes or oceans, eventually forming sedimentary rocks.

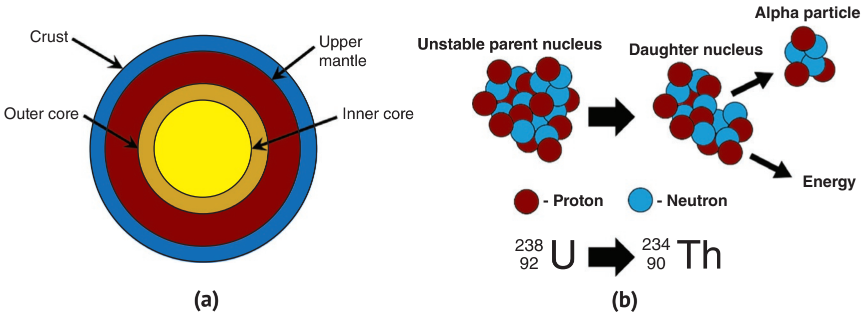


Figure 1.2 Internal structure of Earth (a) and main source of internal heat/energy (b).

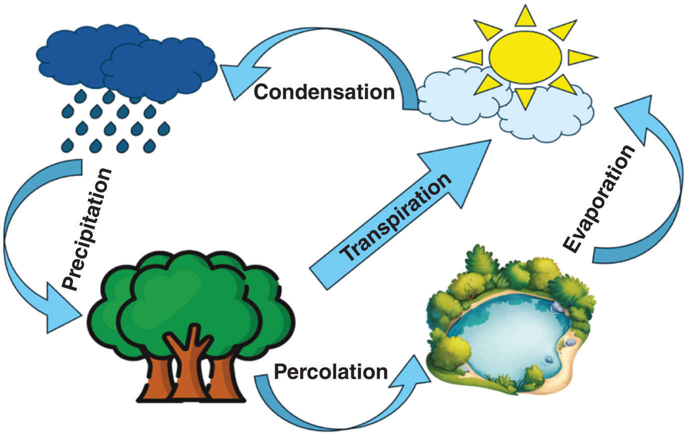


Figure 1.3 Schematics of the hydrological cycle.

To understand the rock cycle, it's convenient to start with magma, which is molten rock beneath the Earth's surface. Magma has temperatures ranging from about 800 to 1,300°C, depending on its composition and the pressure. When magma cools and solidifies, it forms igneous rocks. The location where this cooling occurs determines the type of igneous rock formed:

- *Intrusive igneous rocks*: These form when magma cools slowly beneath the Earth's surface, allowing large crystals to develop. Granite is a common example of intrusive igneous rock.
- *Extrusive igneous rocks*: These form when magma erupts onto the surface (as lava) and cools quickly, resulting in smaller crystals. Basalt is an example of extrusive igneous rock.

Weathering and erosion are critical processes in the rock cycle that break down rocks into smaller particles, which can then be transported and deposited to form sedimentary rocks. Types of weathering:

1. *Physical (mechanical) weathering*: This type of weathering breaks rocks into smaller pieces without changing their chemical composition. It includes:
   - Frost wedging: Water seeps into cracks in rocks, freezes, and expands, causing the rock to break apart.
   - Thermal expansion: Repeated heating and cooling cause rocks to expand and contract, leading to fragmentation.
   - Biological activity: Plant roots grow into cracks in rocks, and animals burrow into the ground, contributing to the mechanical breakdown of rocks.
2. *Chemical weathering*: This involves the chemical alteration of minerals within the rocks, leading to their breakdown. Key processes include:
   - Hydrolysis: Water reacts with minerals to form new minerals and soluble ions. For example, feldspar transforms into clay minerals.
   - Oxidation: Oxygen reacts with minerals, especially those containing iron, to form oxides. This process is responsible for the rusting of iron-rich rocks.
   - Dissolution: Soluble minerals, such as halite and calcite, dissolve in water, especially in acidic conditions.

3. *Biological weathering*: This type of weathering involves the contribution of living organisms. For instance, lichen and moss can produce acids that chemically weather rocks, while tree roots and burrowing animals physically break down rock.

1.1.2 Erosion

Erosion involves the transportation of weathered materials by natural agents. The primary agents of erosion include:

- Water: Rivers and streams carry sediments downstream, where they are deposited in floodplains, deltas, and oceans.
- Wind: In arid regions, wind can transport fine particles over long distances, creating features like sand dunes.
- Glaciers: Moving glaciers pick up and transport large quantities of rock debris, depositing them as glacial till when the ice melts.
- Gravity: Gravity causes rocks and sediments to move downhill through processes like landslides and rockfalls.

Understanding the rock cycle is essential for geologists as it provides insights into Earth's geological history, the formation and distribution of natural resources, and the processes that shape the planet's surface. For example:

- Natural resources: Many natural resources, such as minerals and fossil fuels, are found in specific rock types formed through the rock cycle. For instance, coal forms from buried plant material in sedimentary rock layers, while valuable minerals can be concentrated in igneous and metamorphic rocks.
- Geological hazards: Knowledge of the rock cycle helps in predicting and mitigating geological hazards, such as volcanic eruptions, earthquakes, and landslides.

The rock cycle is not unique to Earth; it can also occur on other planetary bodies, although with significant differences. For instance:

- The moon: The Moon lacks an atmosphere and liquid water, and its tectonic activity is minimal, resulting in a virtually inactive rock cycle.
- Mars: Mars shows evidence of past volcanic activity and ancient river valleys, indicating a once-active rock cycle. However, its current rock cycle is much less active than Earth's due to the absence of liquid water and significant tectonic activity.
- Studying these differences helps scientists understand the unique geological histories of other planets and the factors that influence their evolution.

1.2 Forms of Occurrence of Sedimentary Rocks

Sedimentary rocks are composed mainly of almost parallel layers (strata), differing in physical and chemical properties (Figure 1.4).

The surfaces separating the layers from each other are called the base if it is located below the layer in question and the roof if it is located on top. The line descending perpendicularly from the roof to the sole is called the thickness of the layer (or thickness of the layer); it is also the shortest distance between the roof and the base.

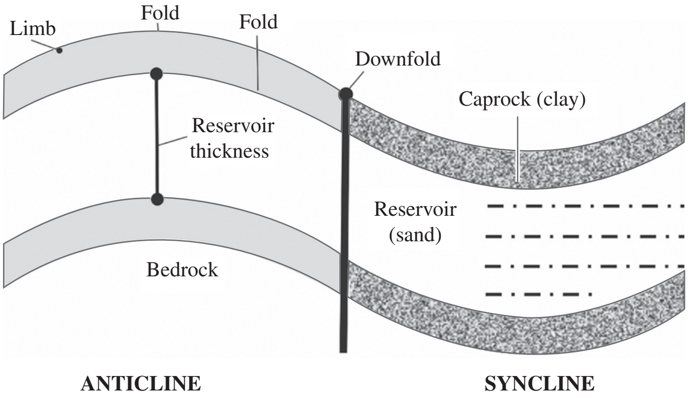


Figure 1.4 Mode of rocks occurrence.

A layer composed of impermeable rocks is called a seal, and one formed from permeable rocks is called a reservoir. In nature, ideally, horizontal occurrence of layers is rarely found; as a rule, they have a wavy (folded) occurrence. This occurrence is due to the fact that the earth's crust is not static, and various oscillatory, tectonic processes constantly occur in it.

The folds formed during these processes are called anticlines and synclines.

Anticline—an anticline is a convex bend in the Earth's crust with a core in the center, with the core composed of older rocks and the outer layers composed of younger rocks.

Syncline—a syncline is the mirror opposite of an anticline, i.e., a concave curve in the Earth's crust with ancient rocks in the outer part and young rocks in the central part. The structural elements of the anticline and syncline are shown in Figure 1.4.

Most of the oil and gas fields are confined to anticlines. Anticlines have an average length of up to 10 km and width up to 3 km. The largest oil field, Ghawar (Saudi Arabia), is located in an anticline 225 km long and 25 km wide.

1.3 Hydrocarbon Reservoirs

For a petroleum engineer, the property of rocks known as permeability is of particular interest, which will be discussed in detail below. For now, let's dwell on the fact that, depending on the permeability of rocks, they are divided into reservoirs and seals. Seals are practically impermeable rocks that act as a dividing surface between reservoir layers.

Reservoirs are rocks that have the ability to contain and release fluids. Mostly reservoir rocks are of sedimentary origin.

The following types of reservoirs are distinguished by pore void structure:

1. *Porous reservoirs*: They consist of voids formed by grain-like debris. For example: sands, sandstones, etc. This type has the best reservoir properties compared to others.

2. *Cavernous reservoirs*: They are mainly associated with carbonate strata and are composed of voids (caverns) formed as a result of leaching or dissolution of salts that make up the rock.
3. *Cracked reservoirs*: This type of reservoir is formed from impermeable rocks; however, numerous fractures of varying sizes allow them to accommodate hydrocarbons. For example, limestones.
4. *Mixed reservoirs*: They are quite common and are a combination of the above types of reservoirs, with the first word in the name indicating the type of predominant rock. For example, cavernous—porous reservoir.

The best reservoir properties. Other types of collectors may also have good abilities to contain and release liquids and gases, as well as pass them through themselves.

It should be noted that there is also a classification of reservoirs by lithological composition:

- terrigenous (silts, sands, etc.),
- carbonate (dolomite, chalk),
- siliceous rocks,
- volcanogenic-sedimentary.

Hydrocarbon deposits are most often found in terrigenous and carbonate reservoirs.

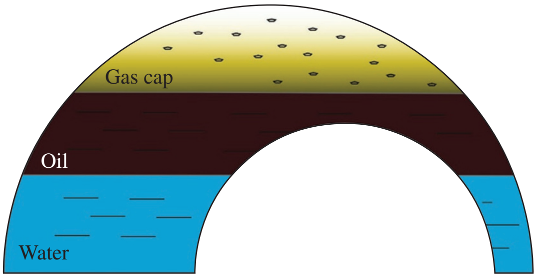
1.4 Oil and Gas Traps

A trap is a part of a reservoir, the conditions of which provide for the accumulation of hydrocarbon reserves. A trap, in essence, is a permeable rock bounded by impermeable layers (seals) in which fluids are in static conditions and distributed according to the law of gravity. This distribution forms the classic structure of an oil field (Figure 1.5).

The fluid interface is named according to the fluids bordering it:

- GWC—gas-water contact,
- WOC—water-oil contact,
- GOC—gas-oil contact.

Figure 1.5 Oil field schematic.



There are two main types of traps:

- structural,
- nonstructural.

Nonstructural traps, in turn, are divided into two types:

- stratigraphic,
- lithological.

1.4.1 Structural Traps

This type of trap, formed due to the migration of hydrocarbons into the fold of the anticline, is called *Anticline (fold) traps* (Figure 1.6). Hydrocarbon migration occurs either along the limbs of anticlines or along tectonic faults.

During tectonic movements of the earth's crust, disturbances in the form of rock formations are often formed. If such a disturbance results in an overlap of the reservoir layer with an impermeable screen (seal), such a trap is called a fault trap (Figure 1.7).

The types of structural traps described above generally have the greatest industrial significance in terms of the availability of potential hydrocarbon reserves.

1.4.2 Lithological Traps

This type of traps is formed due to the lithological dynamics of reservoir rocks, that is, the replacement of permeable rocks with impermeable. The reasons for this process are different, but among the most common of them are the following: pinchout, fracturing and changes in the permeability of reservoir rocks (Figure 1.8). Such traps are formed in the form of sand lenses in clayey deposits (Figure 1.8a) or in reef bodies (limestones) covered by poorly permeable rocks (Figure 1.8b).

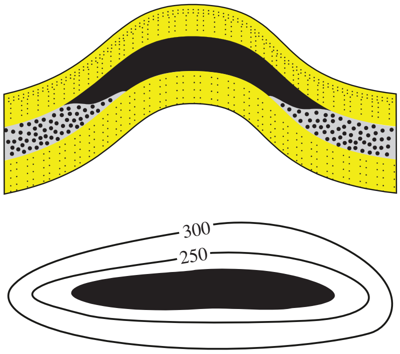


Figure 1.6 Anticline (fold) trap.

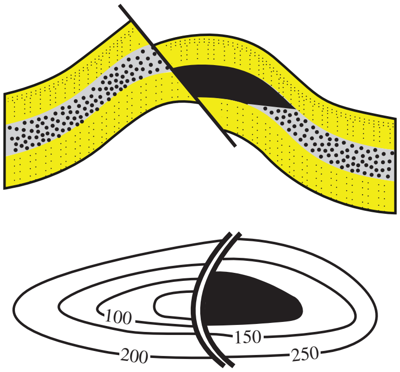


Figure 1.7 Fault trap.

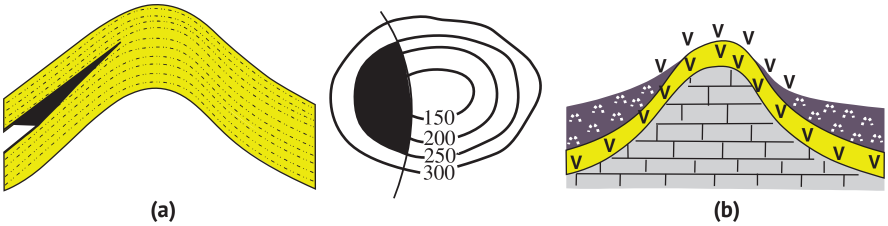


Figure 1.8 (a) Pinch-out trap; (b) a trap confined to a reef massif.

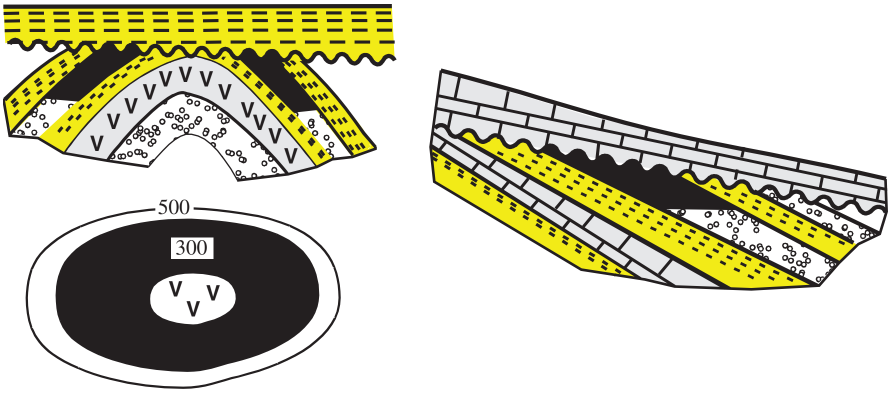


Figure 1.9 Stratigraphic traps.

1.4.3 Stratigraphic Traps

This type of trap is formed by the unconformable overlapping of reservoir rocks with fluid seals (poorly permeable layers). Sometimes a hydrodynamic seal created by formation waters (associated with high-pressure horizons) during filtration along tectonic disturbances can serve as a similar overlapping seal (Figure 1.9).

Quite often, the formation of traps is influenced by several factors, and combined structural and lithological traps are formed.

1.5 Rock Porosity

Porosity is a critical property of reservoir rocks, defined as the ratio of the void space (pores) volume to the bulk volume of the rock, usually expressed as a percentage. This property is fundamental in determining the storage capacity of reservoir rocks for fluids, such as oil, gas, and water. Porosity indicates how much fluid a rock can hold and influences the movement of these fluids through the rock.

1.5.1 Primary and Secondary Porosity

Primary porosity develops during the initial deposition of the rock material. As sediment is deposited and buried, the spaces between the grains form the primary porosity.

Over time, processes like compaction (where grains are pressed closer together under the weight of overlying materials) and cementation (where minerals precipitate from groundwater and fill the spaces between grains) reduce this primary porosity.

Secondary or induced porosity develops after the rock has formed. This type of porosity results from various geological processes, such as fracturing, dissolution, or recrystallization. For example, fractures in shales and limestones or solution cavities known as karsts are forms of secondary porosity. These secondary features can significantly enhance the ability of rocks to store and transmit fluids.

1.5.2 Effective and Total Porosity

From a reservoir engineering perspective, it is essential to distinguish between connected porosity and nonconnected pores (Figure 1.10). Effective porosity refers to the ratio of interconnected void spaces to the bulk volume of the rock, which is crucial for fluid flow within the reservoir. In contrast, total porosity is the sum of both connected and nonconnected porosities. Typically, in sandstones, the total porosity equals the effective porosity, as most pores are interconnected. However, in carbonates such as dolomites and limestones, nonconnected vuggy porosity may occur, where some pores do not contribute to fluid flow.

1.5.3 Diagenesis and Its Impact

Diagenesis refers to the physical and chemical changes that occur in sediment after its deposition, transforming it into sedimentary rock. This process can significantly affect both porosity and permeability. Diagenesis includes various processes, such as mechanical compaction (which reduces pore space by pressing grains closer together), mineralogical changes (altering the mineral composition of the rock), cement precipitation (filling pores with new mineral growth), and mineral dissolution (enlarging pores by dissolving existing minerals) (Figure 1.11). These processes can either enhance or reduce the porosity and permeability of the rock.

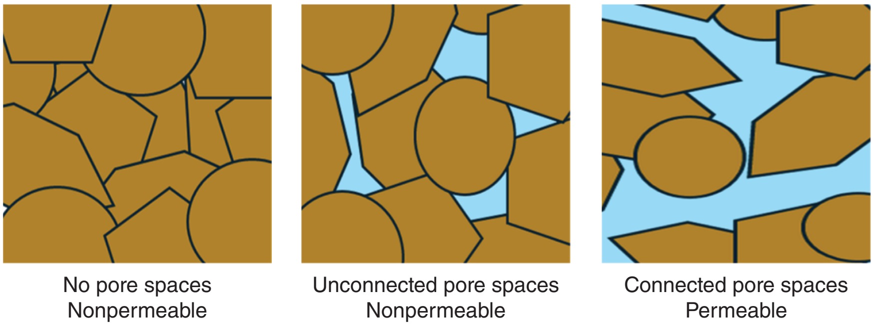
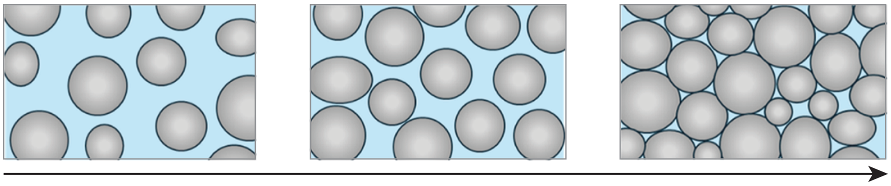
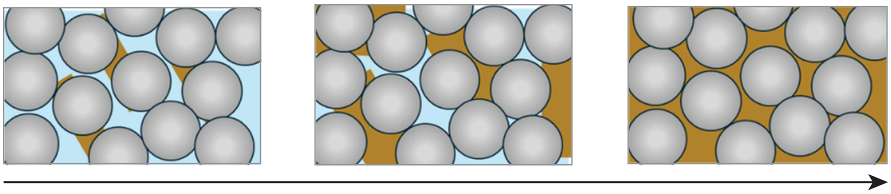


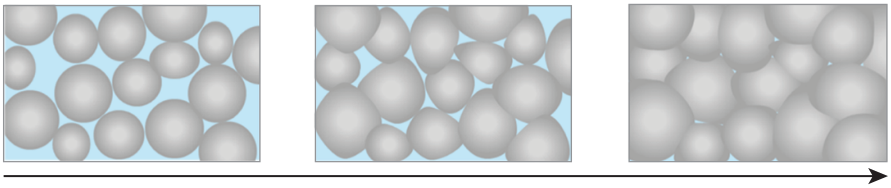
Figure 1.10 Connected/nonconnected pores.



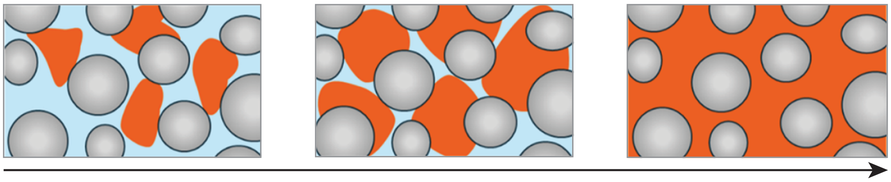
Compaction
During compaction, water is squeezed out of loose sediment and grains may eventually all be in contact.



Cementation
During cementation, chemical cements are deposited from the pore water. They glue individual mineral grains together. Eventually, all the water may be gone, and the sediment may be entirely lithified.



Recrystallization
During recrystallization, small mineral grains may grow into each other and join to become larger crystals of the same mineral. In extreme cases, all the original material may become joined in mosaic pattern.



Recrystallization
During recrystallization, some of the original minerals may dissolve and then precipitate to form new secondary minerals in spaces between grains.

Figure 1.11 Diagenesis.

The porosity of a rock can be influenced by the arrangement of its grains (Figure 1.12). For instance, in a cubic packing arrangement, where grains are arranged in a simple cubic pattern, the porosity can be calculated by considering a cube filled with eight spheres of radius r. The volume of the cube is: $4r^3$ while the total volume of the eight spheres is $8 \times 4/3\ \pi r^3$. The porosity for cubic packing, which is the least compact arrangement, is 47.6%.

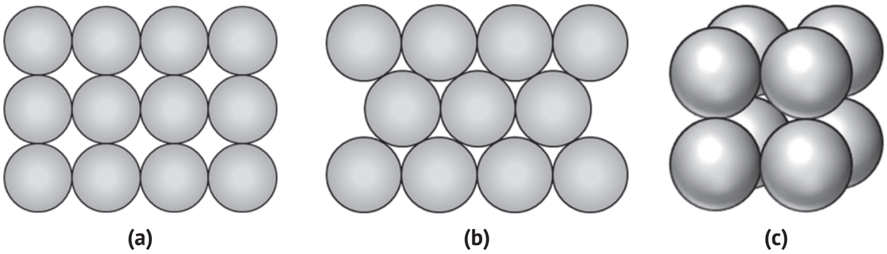


Figure 1.12 (a) Cubic or wide packed; (b) rhombohedral or close-packed; (c) −4 by 4 pack.

Pores space volume is: $(4r)^3 - 8 \times 4/3\pi r^3$.

Porosity: $\varphi = \dfrac{V_B - V_S}{V_B} = 1 - \dfrac{V_S}{V_B} = 1 - \dfrac{32\pi r^3}{3 \times 64r^3} = 1 - \dfrac{\pi}{6}$,

where V_B, bulk volume and V_S, volume of grains.

In contrast, rhombohedral packing represents the most compact arrangement of grains (Figure 1.12c). In this configuration, the spheres are packed as closely as possible, resulting in a lower porosity compared to cubic packing. The porosity of rhombohedral packing is significantly reduced (25.96%) due to the more efficient use of space.

1.5.4 Types of Porosity in Reservoir Rocks

- *Interparticle (intergranular) porosity*: Interparticle porosity, also known as intergranular porosity, is the predominant type found in sucrosic (sugar-like) rocks (Figure 1.13). In these rocks, pore sizes are typically of the same order of magnitude as, but usually less than, the particle sizes. For uniform spherical grains, interparticle porosity ranges from 47.6% in cubic stacking to 25.9% in close packing. However, in the field, these ideal figures are often reduced by variations in grain size and the presence of shale. Permeability in these rocks is influenced not only by porosity but also by sorting, stacking, and grain size. This can range from high permeability in large-grain sandstones (measured in darcies) to impervious conditions in chalks and siltstones.

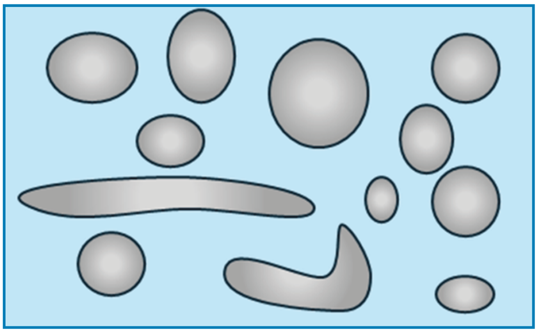


Figure 1.13 Interparticle porosity.

- *Intraparticle porosity*: Intraparticle porosity is the network of pore spaces within individual grains (Figure 1.14). This type of porosity is often revealed by scanning electron microscope (SEM) images. Although intraparticle porosity can contain connate water (water trapped in the rock since its formation), it is usually nearly impervious to fluid flow due to the small size and isolated nature of these pores.
- *Fracture porosity*: Fracture porosity is found in reservoirs that have been fractured, typically in carbonate rocks, such as limestones and dolomites (Figure 1.15). In these reservoirs, the rock is defined as a double porosity medium, consisting of both the matrix (the rock's solid framework) and the fractures. Fractures can significantly enhance permeability by providing additional pathways for fluid flow. Fractured reservoirs are often encountered in crystalline and amorphous rocks, which lack grain size and therefore have minimal interparticle porosity.
- *Vugs and molds*: Vugs and molds, though different in appearance and characteristics, are often classified together (Figure 1.16). Both are formed by the selective dissolution of sedimentary rock by percolating waters. Vugs can vary from the size of a fingernail to large caves and tend to be relatively well connected, allowing for better fluid flow. Molds are typically smaller, often resulting from the dissolution of oolites (small calcite spheres precipitated in seawater). These are known as oolmolds or oolicasts and can exhibit very high porosity, though their connectivity may be poor compared to vugs.

Figure 1.14 Intraparticle porosity.

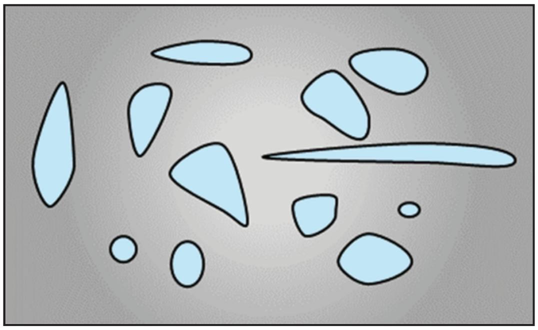
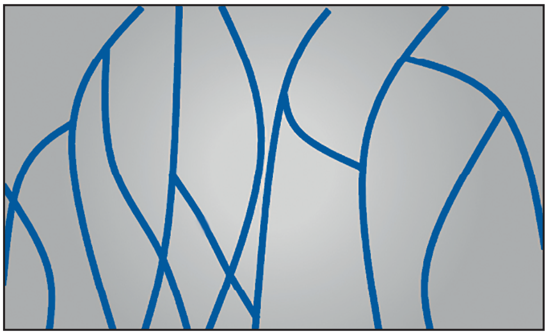


Figure 1.15 Fracture porosity.



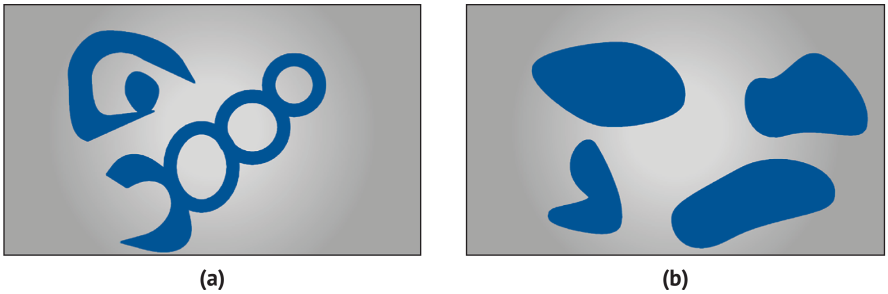


Figure 1.16 (a) Moldic; (b) vugs.

Depending on the diameter, pore channels are divided into three groups:

1. supercapillary (more than 0.5 mm), characterized by free filtration of fluids;
2. capillary (from 0.5 to 0.0002 mm [0.2 μm]), filtration of fluids largely depends on capillary forces; and
3. subcapillary (less than 0.0002 mm [0.2 μm]), filtration of fluids due to large capillary forces is practically impossible, regardless of the porosity value. The most typical examples of such rocks are clays and limestones.

1.6 Rock Permeability

The term “permeability” refers to a crucial property of porous rocks, specifically their ability to conduct fluids. This property plays a significant role in various fields, such as hydrogeology, petroleum engineering, and soil science. Permeability is a key factor in determining how easily fluids, such as water, oil, or gas, can move through subsurface rock formations.

When discussing permeability, it is important to distinguish between different types. If there is only one fluid present within the pore spaces of the rock, this property is termed specific or absolute permeability. Absolute permeability is a fundamental characteristic of the rock, unaffected by the type or properties of the fluid. However, in many practical scenarios, multiple immiscible fluids, such as oil and water, coexist within the pore spaces. In such cases, we refer to the effective permeability of each fluid, which varies depending on the presence and interaction of other fluids in the pores.

To further understand permeability in multi-fluid systems, we use the concept of relative permeability. Relative permeability is the ratio of the effective permeability of a particular fluid to the absolute permeability of the rock. This dimensionless ratio provides insight into how the presence of other fluids affects the flow capacity of the fluid of interest.

Measuring permeability is essentially measuring the fluid conductivity of a material, which is crucial for predicting and managing fluid flow in various applications. The concept of permeability can be analogized to electrical conductivity, where permeability represents the inverse of the resistance that a porous medium offers to fluid flow. Just as electrical conductivity indicates how easily electric current can

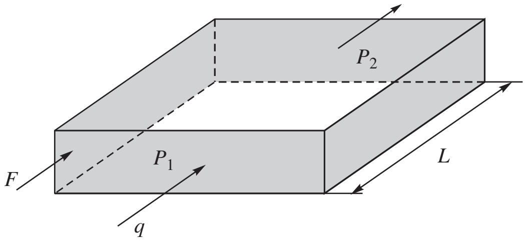


Figure 1.17 Schematic representation of the Darcy equation parameters.

flow through a material, permeability indicates how easily a fluid can flow through a porous rock.

The foundational work on permeability was conducted by Henry Darcy, a French engineer who studied the flow of water through filter sands in the mid-nineteenth century. His pioneering experiments and formulation of what is now known as Darcy's Law laid the groundwork for modern understanding of fluid flow in porous media. As a result, the unit of measurement for permeability is named the "Darcy" in his honor. One Darcy (D) is defined as the permeability that allows a fluid with a viscosity of 1 cP to flow through a porous medium with a pressure gradient of 1 atm/cm at a rate of 1 cm^3/s (Figure 1.17).

Darcy equation:

$$q = \kappa \frac{A}{\mu L}(P_1 - P_2), \tag{1.1}$$

where q, flow rate (cc/s); k, permeability of the rock sample (D); μ, fluid viscosity (cP); A, cross-sample section area (cm^2); L, rock sample length (cm); and P, pressure (atm).

The flow is proportional to:

- Rock permeability
- Cross-sectional area of the sample
- Pressure gradient

And is inversely proportional to:

- Fluid viscosity
- Sample length

Permeability has a dimension of an area. Permeability is usually expressed in milli-Darcy (mD) or μm^2. At the same time, $1\ \text{D} = 1.02 \cdot 10^{-3}\ \mu\text{m}^2 = 1.02 \cdot 10^{-12}\ \text{m}^2 = 1000\ \text{mD}$. The mD is commonly used because the D is relatively large and is convenient only for highly permeable rocks. The Darcy, as a unit, is not derived from a homogenous system of units, yet reservoir engineering techniques have been developed based on equations that use the Darcy unit system. Consequently, analytical formulas in reservoir engineering often refer to the Darcy unit system.

Apart from the Darcy unit system, two other unit systems are commonly used in the industry: field units and metric units. It is crucial to exercise great care when working with reservoir engineering formulas to ensure that the appropriate unit system is applied consistently and correctly. Misapplication of units can lead to significant errors in calculations and interpretations, impacting reservoir performance evaluations and decision-making processes.

1.6.1 Types of Permeabilities

In practice, a distinction is made between absolute, phase, and relative permeability.

1. Absolute permeability is the permeability of a porous medium for a homogeneous fluid inert to the porous medium (usually an inert gas is used), characterizing the physical properties of the rock, but independent of the properties of the saturating fluid.
2. Phase permeability is the permeability of a porous medium for a given fluid in the presence of another. Phase permeability is determined by the degree of saturation of the pores with the studied fluid (oil, gas, water).
3. Relative permeability is the ratio of phase permeability to absolute permeability (measured in fractions of unity).

Initially, Darcy's work focused on describing the flow of a single fluid, specifically water, saturating 100% of the porous medium. The permeability to a particular fluid is independent of the fluid's properties, such as viscosity. Consequently, the permeability to a fluid that completely saturates the porous medium is a constant and inherent characteristic of that medium. This constant is referred to as **absolute permeability** or **specific permeability**.

Relative permeability is a crucial concept in reservoir engineering, especially when dealing with multiphase flow in porous media. While absolute permeability refers to the permeability of a rock when it is fully saturated with a single fluid, relative permeability describes the permeability of each fluid in the presence of other immiscible fluids within the pore spaces.

Relative permeability is defined as the ratio of the effective permeability of a particular fluid to the absolute permeability of the rock. Mathematically, this can be expressed as:

$$\text{Relative Permeability} = \frac{\text{Effective Permeability}}{\text{Absolute Permeability}}. \tag{1.2}$$

This ratio varies depending on the saturation levels of the fluids in the reservoir.

In a two-phase system, the fluids typically consist of combinations, such as oil and water or oil and gas. In contrast, a three-phase system involves the simultaneous presence of oil, water, and gas. As these fluids flow through the porous media, their interactions are influenced by capillary forces. These forces act to reduce the flow rate of each individual phase in a nonlinear manner, due to the competition for available pore space and the complex fluid–fluid and fluid–rock interactions.

As a result of these interactions, the **relative permeability** of each fluid phase is affected by the presence of the other phases. Consequently, the sum of the relative permeabilities of all phases in a given porous medium is always less than one. This reflects the fact that the presence of multiple fluids reduces the effective permeability of each individual phase compared to a situation where only one fluid is present.

$$k_{ro} + k_{rw} + k_{rg} < 1. \tag{1.3}$$

Absolute permeability is often approximated as the effective permeability to air.

The relative permeability of a fluid is influenced by several factors, including fluid saturations, wettability of the rock, and the interaction between the fluids.

Relative permeability curves are typically obtained through laboratory experiments and are used to describe the flow characteristics of oil, water, and gas in reservoir rocks. These curves help engineers to better understand and manage the production performance of a reservoir, facilitating more efficient and effective recovery strategies.

1.6.2 Klinkenberg Effect

It has been observed that the measured absolute permeability of a sample varies depending on whether air or liquid is used for the measurement. In the case of low-pressure gas flow, the mean free path of gas molecules is comparable to the pore size of the medium. As a result, the likelihood of collisions between gas molecules and the solid grains of the porous media is similar to the likelihood of collisions between gas molecules themselves. This reduces the relative influence of viscous forces during gas displacement, leading to an overestimation of permeability when applying Darcy's law. Consequently, the apparent permeability measured with gas is higher than that measured with a liquid.

The linear relationship between the observed permeability and the reciprocal of the mean pressure can be expressed as:

$$\begin{aligned} k_L = \frac{k_g}{1+\frac{b}{\overline{P}}} &= k_g - m\frac{1}{\overline{P}}, \\ b &= \frac{m}{k_L} \end{aligned} \tag{1.4}$$

where k_L, absolute permeability measured with liquid; k_g, absolute permeability measured with gas; $\overline{P}$, mean flowing pressure during the displacement; b, constant for a given gas in a given medium; and m, slope of curve.

$$k_{app} = \frac{k_L + b}{P_{mean}}, \tag{1.5}$$

where k_{app} is the apparent permeability measured with gas. k_L is the Klinkenberg permeability, representing the permeability at infinite pressure. b is a constant that depends on the mean free path of the gas and the size of the openings in the porous media. P_{mean} is the mean pressure in the core.

The parameter b is influenced by both the mean free path of the gas and the size of the openings in the porous media, indicating that b is a function of permeability. This correction is essential to accurately determine the permeability of porous media when using gas as the flowing fluid, particularly in tight formations where the pore sizes are small.

Reservoirs are conventionally ranked into five classes based on permeability:

- very well permeable (more than 1 μm^2),
- highly permeable (0.1–1 μm^2),
- medium-impermeable (0.01–0.1 μm^2),
- weakly permeable (0.001–0.01 μm^2), and
- impenetrable (less than 0.001 μm^2).

The first three classes of reservoirs are of industrial interest.

1.7 Geological Heterogeneity of Rocks

Geological heterogeneity is one of the most important characteristics affecting the efficiency of the field development process. Typically, two types of heterogeneity are distinguished: microheterogeneity associated with the heterogeneity of the pore space within one formation, and macroheterogeneity associated with the heterogeneity of the oil-bearing strata that make up the reservoir.

Microheterogeneity of the rock manifests itself when there is a significant difference in the fractional composition. A significant variety of fractional composition leads to the formation of capillary and subcapillary pores. In capillary pores the liquid moves, but in subcapillary pores it is motionless due to the molecular-surface interaction of the liquid and the rock. In this case, the continuity of capillary pores overlapped by subcapillaries may also be disrupted. In addition, other parameters in the formation can vary greatly, such as lithological properties, clay content, carbonate content, and degree of cementation. As a result, small zones with different permeability appear within one formation. At the same time, such formations are characterized by average permeability and are considered in calculations as homogeneous (or quasi-homogeneous), despite the fact that microheterogeneity has a significant impact on the effectiveness of the applied methods of influencing the reservoir.

There are two types of macroheterogeneity:

- along the strike of the formation (zonal heterogeneity) and
- along the dip of the formation (layered heterogeneity).

Macroheterogeneity is manifested in the variability of reservoir properties (primarily permeability) of zones and layers along the strike and dip of the formation.

The macroheterogeneity of a deposit is assessed by several coefficients:

- The compartmentalization coefficient is the ratio of the sum of permeable layers in all wells to the number of wells. In the case when the productive horizon is represented by one layer, the separation coefficient is equal to one. How the more permeable layers in the section, the higher the coefficient of compartmentalization.
- Sandiness coefficient is the ratio of the effective thickness of the formation to its total thickness. The sandiness coefficient allows you to estimate the ratio of reservoirs and nonreservoirs in the section of the object.

The higher the coefficient of dissection and the lower the coefficient of sandiness, the higher the degree of macroheterogeneity of the operational object.

Macroheterogeneity along the dip, or layered heterogeneity, is characterized by another indicator, namely the presence of crossflows between layers. This indicator has a significant impact on hydrodynamic calculations and reservoir development. In the case when there are clay interlayers (tires) between the layers, there are practically no crossflows.

1.8 Saturations

In underground oil and gas reservoirs, the pore spaces in the rocks are always completely saturated with fluids. There is no true "void space" in these pores; they are filled with one or a combination of the following fluids:

1. Oil (and associated impurities in the liquid phase)
2. Natural gas (and associated impurities in the vapor phase)
3. Water (either connate water, present since the rock's formation, or water that entered the reservoir later, possibly through injection)

Initially, when the rock was deposited in an aqueous environment, the pore spaces were 100% water-saturated. Over time, during the processes of burial, compaction, and cementation, water composition might have changed, but the saturation remained full unless hydrocarbons entered the pores and displaced some of the water.

Hydrocarbons can enter the pores if the water-saturated rock is near an active hydrocarbon source, like organic-rich shale, and if the pores are in pressure communication with this source rock. Hydrocarbons, being less dense than water, move upwards through the porous and permeable rock until they either escape at the surface or are trapped by an impermeable layer, forming an oil or gas reservoir if the conditions are suitable.

Despite hydrocarbon entrapment, some water always remains in the pores, leading to the fundamental saturation relationship in reservoirs:

$$S_o + S_w + S_g = 1.0, \tag{1.6}$$

where:

$$S_o = \frac{\text{oil volume}}{\text{pore volume}} = \frac{V_o}{V_p},$$

$$S_w = \frac{\text{water volume}}{\text{pore volume}} = \frac{V_w}{V_p},$$

$$S_g = \frac{\text{gas volume}}{\text{pore volume}} = \frac{V_g}{V_p}.$$

It's possible for oil or gas saturation to be zero in some cases, but water saturation is always greater than zero.

Saturation is a key measure of the fluid content in porous rock and directly influences a reservoir's hydrocarbon storage capacity. It is also useful in identifying gas/oil or oil/water contacts based on changes in residual saturation with depth and serves as a correlation variable for estimating reservoir productivity.

1.8.1 Saturation Distribution in Reservoirs

During hydrocarbon accumulation, water saturation in the reservoir can be reduced to a point where it becomes immobile, typically between 5 and 40%, at which no more water can escape from the pores. This immobile water level is known as irreducible water saturation. It is important to distinguish between the different terms used for water saturation in the petroleum literature. Here are the key definitions:

1. S_{wir}—**Irreducible water saturation**: Below this point, water cannot flow.
2. S_{wc}—**Connate water saturation**: This is the water saturation when the reservoir is discovered. It may or may not be irreducible, so careful interpretation is needed.
3. S_{wi}—**Initial water saturation**: This can refer to irreducible, connate, or interstitial saturation (water present in the pores). It may not signify irreducible and can refer to water saturation at discovery or at any other point in time.

Due to the density differences between gas, oil, and water, typical reservoirs have oil floating on water and, if present, gas floating on oil. Even at the very top of a reservoir, there will always be some level of water saturation, at least at irreducible water saturation.

1.8.2 Fluid Distribution in Reservoirs

In a theoretical case without a porous medium (where porosity = 100%), the fluid layers in a container of oil, gas, and water would have distinct interfaces:

- Gas cap: $S_g = 100\%$
- Oil zone: $S_o = 100\%$
- Aquifer (water zone): $S_w = 100\%$

However, in actual porous rock reservoirs, the fluid interfaces are not so distinct. Water saturation is present throughout the oil and gas zones at a level of at least irreducible water saturation. Additionally, fluid contacts (such as the GOC and oil-water contact [OWC]) are spread over a transition zone that can range from a few feet to tens of feet, depending on fluid density differences and the permeability of the rock.

Figure 1.18 shows a simplified example of how oil, gas, and water would arrange themselves if there was no rock or porous material—essentially like fluids in a jar. In this case:

- *Gas cap* (*top*): The gas would float on top because it's the lightest fluid. So, in the gas cap, the **gas saturation (S_g)** would be 100%, meaning that there is only gas.
- *Oil zone* (*middle*): Below the gas, you would have oil. Here, the **oil saturation (S_o)** would be 100%, meaning only oil is present.
- *Water zone* (*bottom*): At the bottom, you'd have the heaviest fluid, water. The **water saturation (S_w)** would be 100%, meaning it's entirely water.

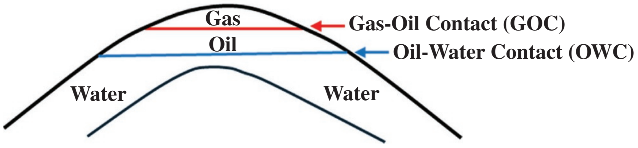


Figure 1.18 Cross section of reservoir showing vertical segregation of fluids.

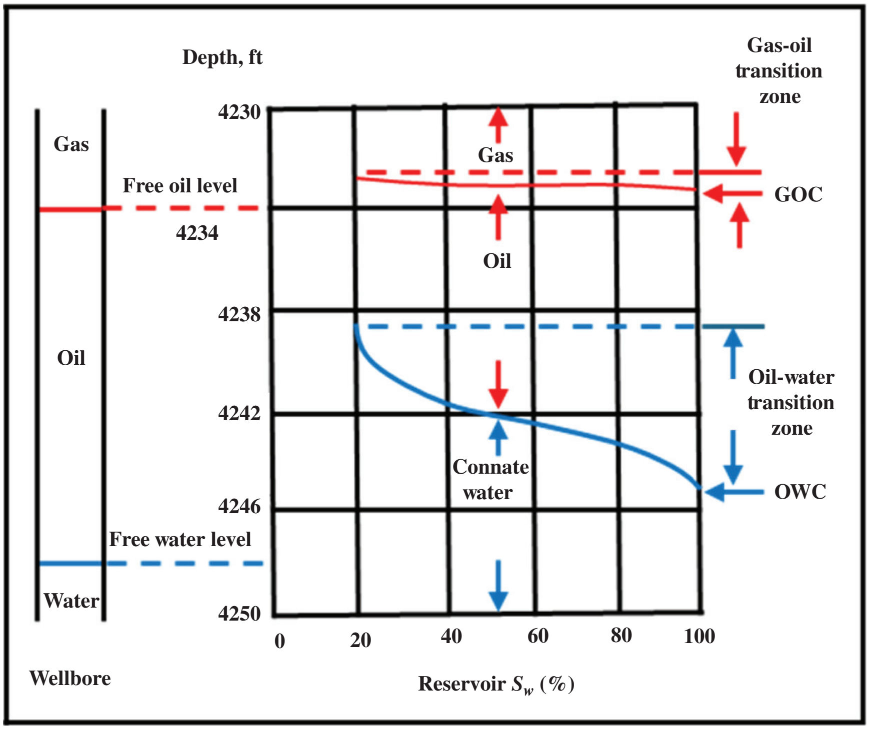


Figure 1.19 Normal initial fluid distribution in a reservoir of uniform permeability and static equilibrium.

This is an **idealized model**, where fluids do not mix, and the interfaces between gas, oil, and water are very clear-cut and distinct.

In the real world, reservoirs are made of porous rock, and things aren't so simple. Figure 1.19 gives a more realistic view of how fluids actually distribute in the pores of a reservoir rock. The transitions between gas, oil, and water aren't sharp, and fluids can be mixed at certain levels.

Here's a breakdown of what Figure 1.19 shows:

1. Gas cap:
    - At the very top of the reservoir, you still have gas, but there is some water mixed in with it. So, even in the gas cap, $\boldsymbol{S_g \neq 100\%}$ because some of the space is taken up by **irreducible water saturation ($\boldsymbol{S_{wir}}$)**—this is water that cannot be displaced, no matter how much gas is present.
    - GOC: This is the point where the gas and oil meet, located at 4233.5 ft.
2. Gas-oil transition zone:
    - This zone is a mix of gas and oil. The gas saturation (S_g) decreases as you go deeper, and oil saturation (S_o) increases.
    - This transition happens over a small depth, about 1 ft (4232.5–4233.5 ft).
3. Oil zone:
    - The bulk of the oil is located below the gas-oil transition. However, even in the pure oil zone, some water is still present due to irreducible water saturation (S_{wir}),

which can't be displaced. So, the oil saturation (S_o) here is close to but not exactly 100%.
- OWC: This is the point where oil and water meet, located at 4245 ft.

4. Oil-water transition zone:
   - As you go further down, the oil decreases, and the **water saturation (S_w)** increases. This transition happens over a few feet (from 4238.5 to 4245 ft).
   - This zone has a gradual change from mostly oil with some water at the top to mostly water with some oil at the bottom.
5. Water zone (aquifer):
   - Below the OWC, there is mostly water. But as always, some oil remains trapped in the pores, even in this zone.
   - The **free water level (FWL)** is at 4248 ft, where the water is the dominant fluid.

In Figure 1.20, the distribution of saturation is shown across the OWC and through the oil-water transition zone, illustrating how saturation levels change across these interfaces in a real-world reservoir.

When measuring fluid saturations from core samples, the core's fluid content is often altered due to two primary processes:

1. Mud invasion: Mud or mud filtrate used in drilling enters the formation and affects the core's original fluid content, especially oil and water saturations.
2. Pressure release: As the core is extracted to the surface, the drop in confining pressure causes gas to expand and fluids to be expelled, especially water.

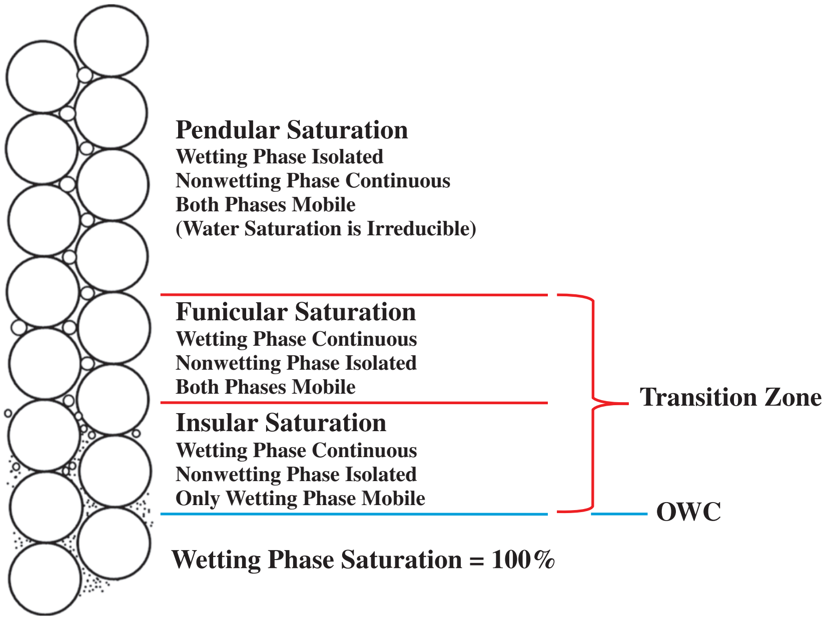


Figure 1.20 Microscopic cross section of OWC and transition zone.

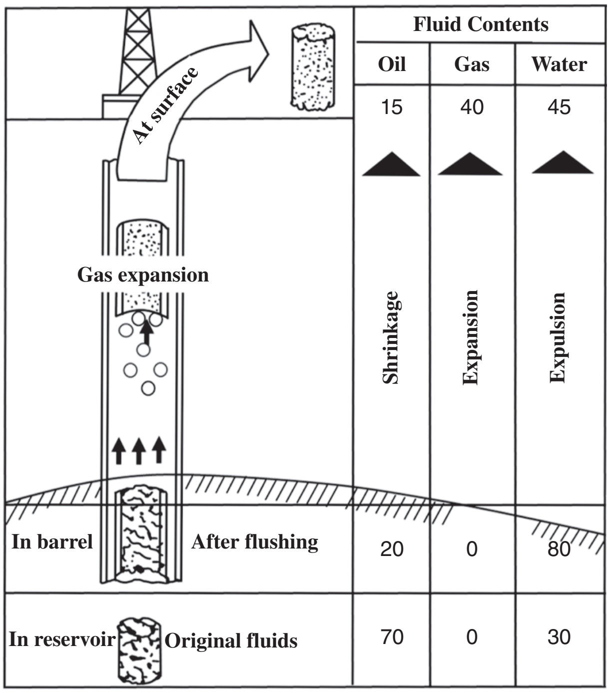


Figure 1.21 Example of saturation changes occurring in the core from *in situ* to surface conditions.

In Figure 1.21, you can observe these changes from *in situ* conditions to the surface. Oil saturation decreases, mainly because of mud invasion, while gas expands as pressure decreases, pushing water out of the core. Additionally, as pressure and temperature drop, oil shrinks in volume, further reducing its saturation.

Several methods have been suggested to minimize these issues. Using oil-based muds (OBM) as the drilling fluid can help reduce mud invasion. Another approach involves using empirical correction factors to adjust measured saturations back to their *in situ* values (Amyx et al., 1960). In some cases, geophysical well logs or capillary pressure measurements are used as alternatives to core analysis for estimating *in situ* saturations.

1.9 Resistivity

The presence of hydrocarbons in a formation can be identified by measuring the electrical resistivity of the rocks. The resistivity depends on several factors, primarily the pore geometry and fluid distribution within the rock. The key variables include the size, type, and interconnection of pore spaces, as well as the type and distribution of fluids, such as oil, gas, and water.

1.9.1 Electrical Properties of Rocks

- The rock matrix itself acts as a perfect insulator and does not conduct any electrical current.
- Conductivity occurs through the fluids present in the pore spaces of the rock, a process known as ionic or electrolytic conduction. This is caused by the movement of ions (such as Na^+ and Cl^-) in the formation water.
- The higher the salinity of the water, the more ions it contains, resulting in greater conductivity. Therefore, highly saline water will exhibit lower resistivity.
- In contrast, oil and gas are insulators, meaning that a hydrocarbon-bearing formation will have lower conductivity (or higher resistivity) than a water-bearing formation of the same porosity.

The electrical properties of rocks and their pore geometry are described by **Archie's Law**, which is fundamental to understanding the volume fraction of fluids in the pore space. Archie's Law is central to the interpretation of well logs, which are used to infer the presence of hydrocarbons.

1.9.2 Basic Concepts: Ohm's Law and Resistivity

To introduce the concept of resistivity in rocks, consider an example using a simple open-top cubic tank with dimensions of one meter in all directions. The tank is electrically nonconductive, except for two metal electrodes on opposite sides (Figure 1.22).

1. The tank is first filled with salt water (simulating formation water), and a voltage (v) is applied across the electrodes. The resulting current (i) is measured.
2. Using Ohm's Law, the resistance of the water can be calculated:

$$r_w = \frac{v}{i}. \tag{1.7}$$

3. The resistivity of the water (R_w) is calculated by scaling the resistance with the aspect ratio of area to length, i.e., the tank's cross-sectional area (A) to its length (L):

$$R_w = r_w \frac{A}{L}. \tag{1.8}$$

   Resistivity is measured in ohm-meters and is inversely proportional to both salinity and temperature—higher salinity or temperature results in lower resistivity.
4. Next, sand is added to the water-filled tank, displacing some of the water. This creates a porous medium that is 100% saturated with water. Since the rock grains (sand) act as insulators, the current must pass through the remaining water, which increases the resistance. The resistance associated with this porous, water-saturated medium is denoted as r_o, and the corresponding resistivity is R_o (Figure 1.23).

The increase in resistance is due to the tortuous path the electrical current must take to circumvent the nonconductive sand grains. This path is longer than the direct path through water, resulting in higher resistance. The tortuous path length is referred to as L_a, and the cross-sectional area through which current flows is A_a.

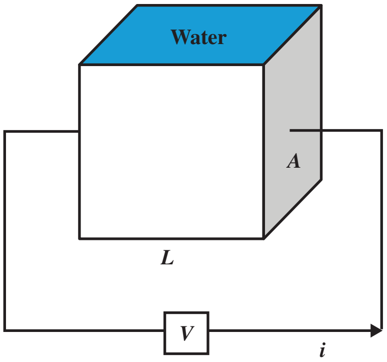


Figure 1.22 Definition of water resistivity.

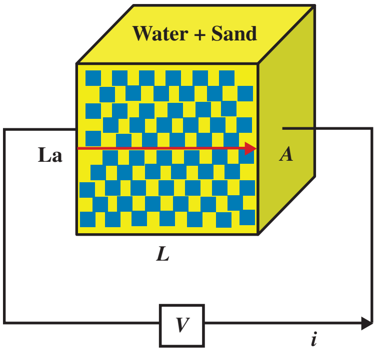


Figure 1.23 Definition of a 100% water-saturated sand.

1.9.3 Formation Resistivity Factor

The resistivity of the rock in this water-saturated state is proportional to the resistivity of the water (R_w) because only the water conducts electricity. This relationship is expressed as:

$$F = \frac{R_o}{R_w}, \tag{1.9}$$

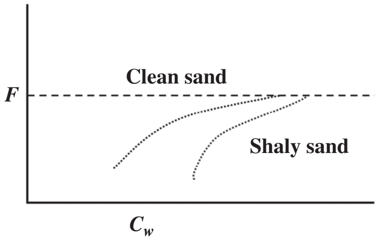
where F is the formation resistivity factor, a proportionality constant that accounts for the increased resistance due to the presence of the rock matrix. Understanding the formation resistivity factor is crucial for accurately interpreting well logs and determining fluid saturation within the formation.

The formation factor (F) is independent of the water resistivity, as shown by the horizontal line in Figure 1.24. The formation factor, defined as the ratio of resistivity in a water-saturated rock to the resistivity of the water, can be described as:

$$\frac{R_o}{R_w} = \frac{A}{A_a}\frac{L_a}{L}, \tag{1.10}$$

where R_o is the resistivity of the water-saturated formation, R_w is the resistivity of the formation water, A is the area of the system, and A_a is the area available to the current, L is the length of the system, and L_a is the tortuous path length the current follows.

Figure 1.24 Relationship between F and water conductivity.



1.9.4 Tortuosity and Porosity

The concept of tortuosity (τ) describes the complexity of the path that the electrical current must take through the pore spaces:

$$\tau = \left(\frac{L_a}{L}\right)^2. \tag{1.11}$$

Porosity (φ) represents the fraction of the rock that is made up of void spaces:

$$\varphi = \frac{A}{A_a}. \tag{1.12}$$

These definitions allow us to express the formation factor (F) as:

$$F = \frac{\sqrt{\tau}}{\varphi}. \tag{1.13}$$

This equation shows that the formation factor is directly related to pore geometry, including the porosity and tortuosity of the formation.

1.9.5 Empirical Relationships and Cementation

Laboratory-measured formation factors provide accurate results for specific rock types. However, lab tests are limited to formations where core samples have been retrieved. In cases where core samples are unavailable, empirical correlations like Archie's Law are often used. Archie established a general relationship between porosity and formation factor:

$$F = a \times \varphi^{-m}, \tag{1.14}$$

where a is the **cementation factor** and m is the **cementation exponent**.

The term **cementation** describes how tightly the grains in a rock are bound together. As the degree of cementation increases, the cementation exponent (m) increases from around 1.3 in unconsolidated rocks to 2.2 in highly cemented rocks. For a formation factor of 20, this change in the cementation exponent translates into a change in porosity from 10 to 26%. The empirical constants in Archie's Law depend on various factors, including cementation, tortuosity, and wettability.

1.9.6 Resistivity Index and Water Saturation

When hydrocarbons are present in the pore spaces, they act as insulators, increasing the formation's resistivity (Figure 1.25). The resistivity of a formation that contains hydrocarbons is denoted as R_t. The resistivity index (I) is defined as the ratio of the resistivity of the hydrocarbon-bearing formation to the resistivity of the formation 100% saturated with water:

$$I = \frac{R_t}{R_o}. \tag{1.15}$$

Archie correlated the Resistivity Index with water saturation (S_w) using the following relationship:

$$I = \frac{R_t}{R_o} = \frac{1}{S_w^n}, \tag{1.16}$$

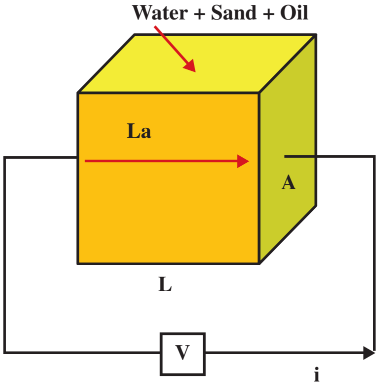


Figure 1.25 Resistance in a hydrocarbon-bearing formation.

where n is the b. When the formation is completely saturated with water ($S_w = 1$), the resistivity of the formation equals R_o (i.e., $R_t = R_o$). Conversely, when the formation contains only hydrocarbons ($S_w = 0$), the resistivity tends toward infinity ($R_t \rightarrow \infty$).

By rearranging Eq. (1.16) and assuming ($n = 2$), we can solve for **water saturation**:

$$S_w = \sqrt{\frac{R_o}{R_t}}. \tag{1.17}$$

This equation is applicable when a hydrocarbon-bearing zone overlays a water-bearing zone with similar porosity and water salinity. To generalize this equation for any permeable hydrocarbon zone, Archie extended it by substituting Eq. (1.9) for R_o, resulting in:

$$S_w = \sqrt{\frac{FR_w}{R_t}}. \tag{1.18}$$

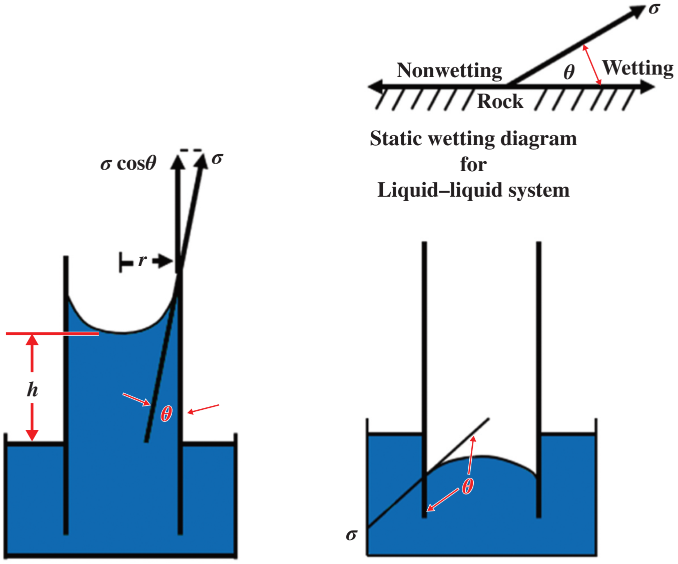
This expression is known as **Archie's Relation** or **Archie's Law**, which remains a fundamental tool for determining water saturation and evaluating hydrocarbon reserves in porous formations.

1.10 Capillary Pressure

Reservoir rocks consist of tiny pores, and the small pore sizes, combined with the interfacial tension between the immiscible fluids (such as water and hydrocarbons), lead to **capillary pressure**. This pressure plays a critical role in determining fluid distributions within the reservoir.

Porous reservoir rocks can be thought of as a collection of capillary tubes, where capillary pressure is generated at the interface between immiscible fluids. Capillary pressure is the pressure difference across the interface formed by two immiscible fluids in these small tubes. Figure 1.26 illustrates capillary tubes immersed in both wetting and nonwetting liquids:

- In a **wetting liquid**, the liquid climbs up the capillary tube (capillary rise), as observed with water in a glass tube.
- In a **nonwetting liquid**, the liquid is depressed (capillary depression), as seen with mercury in a glass tube.



Capillary rise of wetting fluid

Capillary depression of non-wetting fluid

Figure 1.26 Capillary tubes in wetting and nonwetting fluids.

The capillary pressure in a tube is influenced by the interfacial tension between the fluids, the contact angle between the rock and the fluid, and the radius of the tube. Using Figure 1.26, the equilibrium in the capillary tube leads to a force balance equation:

$$\text{force up} = \text{force down},$$

$$\text{force up} = 2\pi r\sigma \cos\theta,$$

$$\text{force down} = \pi r^2 h\Delta\gamma.$$

Since capillary pressure (P_c) is defined as the force per unit area:

$$P_c = \frac{\textit{force up}}{\pi r^2} = \frac{2\sigma \cos\theta}{r}, \tag{1.19}$$

where r is the **pore radius** (cm), σ is the **interfacial tension** (dynes/cm), and θ is the **contact angle** between the fluid and the solid surface (degrees).

Laboratory measurements of capillary pressure often require corrections for several factors:

1. *Closure*: Effects caused by surface irregularities of the core sample.
2. *Microporosity*: Leads to “double curves” due to a different capillary entry point at lower water saturations.
3. *Confining stress*: Affects the magnitude of porosity and permeability.
4. *Presence of clays*: Alters effective water saturation.
5. *Wettability and interfacial tension differences*: These differ between laboratory fluids and reservoir fluids.

Among these, **wettability** and **interfacial tension differences** are particularly important. In practice, capillary pressure is often converted to height above the FWL to develop a **saturation profile**. The height at which water stands above the FWL is proportional to the capillary pressure.

Expanding on Eq. 1.19, the following expression can be derived for capillary pressure:

$$P_c = \frac{\pi r^2 gh(\rho_w - \rho_{air})}{\pi r^2} = \Delta\rho gh, \tag{1.20}$$

where H is the height of capillary rise (ft), P_c is the capillary pressure (psi), ρ_w is the density of water or wetting phase (slugs/ft^3 or kg/m^3), and ρ_{air} is the density of air or nonwetting phase (slugs/ft^3 or kg/m^3).

From Eq. 1.19, we observe that **larger pore radii** result in **lower capillary pressure**. From Eq. 1.20, lower capillary pressure leads to a lower height of water rise in the reservoir.

- Low capillary pressure and low irreducible water saturations are found in reservoir rocks with large pores, such as coarse-grained sandstones, coarse-grained oolitic carbonates, and vuggy carbonates.
- High capillary pressure and high water saturations are associated with fine-grained reservoir rocks.

1.10.1 Capillary Pressure in Reservoirs

In reservoir systems, capillary pressure (P_c) is the pressure difference between the nonwetting-phase pressure (P_{nw}) and the wetting-phase pressure (P_w):

$$P_c = P_{nw} - P_w. \tag{1.21}$$

Capillary pressure is always positive, and in water-wet oil reservoirs, it can be described as the pressure difference between the oil and water phases:

$$P_{cow} = P_o - P_w. \tag{1.22}$$

Similarly, in a water-wet gas reservoir or gas cap:

$$P_{cgw} = P_g - P_w. \tag{1.23}$$

When oil and gas coexist in a reservoir, the oil phase typically behaves as the wetting phase relative to the gas phase. Therefore, the capillary pressure between the gas and oil phases is:

$$P_{cog} = P_g - P_o. \tag{1.24}$$

Capillary pressure and gradients arise due to the density differences between oil, gas, and water, as well as their immiscibility. These factors influence the distribution of fluids in the reservoir, as shown in Figure 1.27.

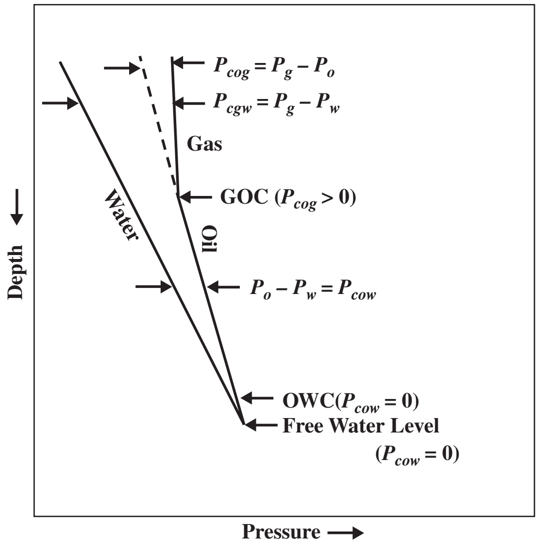


Figure 1.27 Capillary pressure in reservoirs.

1.10.2 Laboratory Capillary Pressure Measurements

While it would be ideal to measure capillary pressure using actual reservoir oil and water at reservoir temperature, practical difficulties, such as obtaining representative samples and handling them in the laboratory, make this challenging. Instead, substitute fluids are used, and results are adjusted for reservoir conditions (Table 1.1).

Table 1.1 Typical interfacial tension and contact angle constants.

System	Contact angle, θ (deg.)	Interfacial tension, σ (dynes/cm)
Laboratory		
Air–water	0	72
Oil–water	30	48
Air–mercury	140	480
Air–oil	0	24
Reservoir		
Water–oil	30	30
Water–gas	0	50[a]

a. Pressure and temperature dependent, reasonable value to depth of 5000 ft. The equation for correcting laboratory-measured capillary pressure to reservoir conditions is:

$$P_{c(res)} = P_{c(lab)} \frac{(\sigma\ \cos\theta)_{res}}{(\sigma\ \cos\theta)_{lab}}, \tag{1.25}$$

where $P_{c(res)}$ = capillary pressure corrected to reservoir conditions (psig), $P_{c(lab)}$ = capillary pressure measured in the laboratory (psig), σ_{res} = interfacial tension between reservoir fluids under reservoir conditions (dynes/cm), σ_{lab} = interfacial tension between laboratory fluids under laboratory conditions (dynes/cm), θ_{res} = contact angle for reservoir conditions and fluids (degrees), and θ_{lab} = contact angle for laboratory conditions and fluids (degrees).

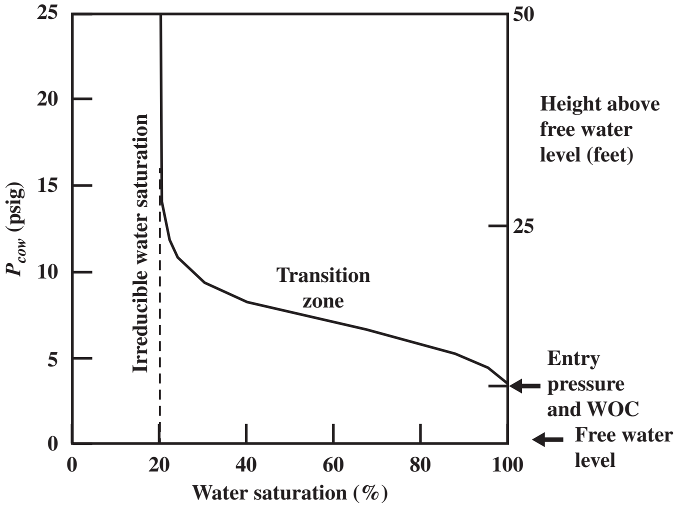


Figure 1.28 Conventional capillary pressure curve.

1.10.3 Entry Pressure

In water-wet reservoirs, water (the wetting phase) is more readily attracted to the rock surface, while the nonwetting phase (usually oil) requires additional pressure to enter the rock. This pressure is known as the **entry pressure**—the minimum capillary pressure required to force the first droplet of oil into the rock.

- Initially, oil enters the **largest pores** of the rock.
- As capillary pressure increases, oil enters smaller pores, reducing water saturation at increasing depths above the OWC.

Figure 1.28 illustrates a conventional capillary pressure curve for a water-wet oil reservoir. The FWL is the depth where the capillary pressure between oil and water is zero. However, the OWC, where oil saturation first appears, occurs at a shallower depth, where the capillary entry pressure is reached.

As capillary pressure rises, more oil enters smaller pores, displacing water and establishing fluid saturations in the reservoir.

1.10.4 Hysteresis—Imbibition Versus Drainage

The relationship between capillary pressure and saturation is dependent on the direction of saturation change, as demonstrated in Figure 1.29.

- *Drainage Curve*: Represents the process of oil migrating into a reservoir initially filled with water (100% water saturation). The nonwetting oil phase enters the reservoir at entry pressure. As capillary pressure increases, oil saturation also rises, causing a decrease in water saturation. This reduction in wetting-phase saturation is referred to as a drainage process, which continues until it reaches the irreducible water saturation level, S_{wi}.

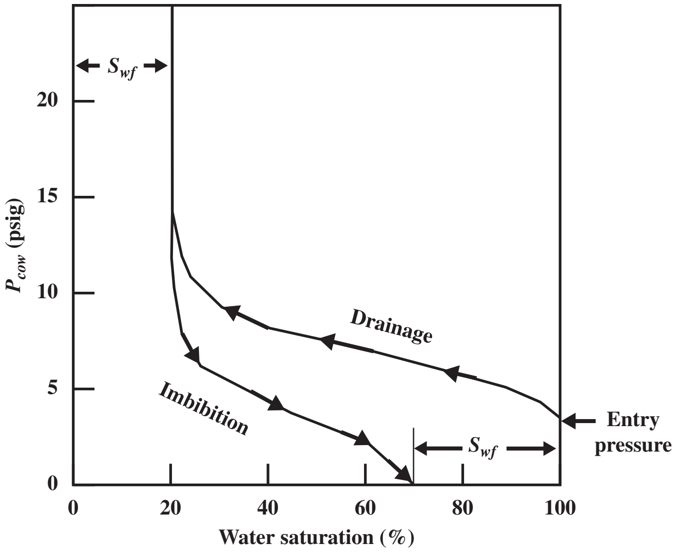


Figure 1.29 Imbibition and drainage capillary pressure curves illustrating hysteresis.

- *Imbibition Curve*: Illustrates the reverse process, where water is injected into the reservoir that was at irreducible water saturation (as in a waterflooding operation). The arrows on this curve indicate increasing water saturation, where water is being imbibed into the rock. This process is known as imbibition.
- *Hysteresis*: The difference between the drainage and imbibition curves is known as hysteresis, a key feature that shows how saturation behavior differs based on the direction of change.
- *Residual Oil Saturation* (S_{or}): Even after imbibition, some oil remains trapped in the reservoir and cannot be displaced by water. This trapped oil is referred to as the residual oil saturation, S_{or}.

1.10.5 Permeability Effects

Capillary pressure and irreducible water saturation are inversely related to pore size. As pore size increases, capillary pressure and irreducible water saturation decrease. Figure 1.30 demonstrates the relationship between permeability and capillary pressure, and Table 1.2 summarizes the key permeability effects. In larger pores, lower capillary pressure means that the reservoir rock holds less water at irreducible saturation levels.

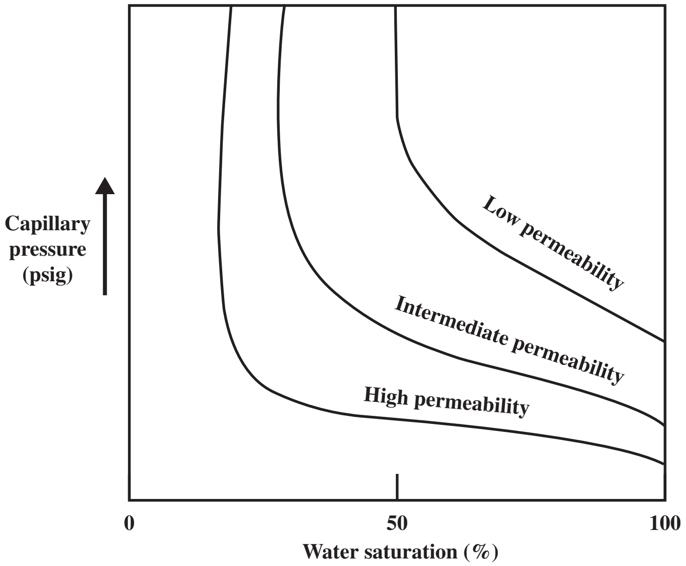


Figure 1.30 Effect of permeability on capillary pressure.

Table 1.2 Permeability effects.

Property	High permeability	Low permeability
Entry pressure	Lower	Higher
Irreducible water saturation	Lower	Higher
Slope of transition zone curve	Lower	Higher
Grain size distribution	Narrow	Wide
Grain and pore size	Large	Small

1.10.6 Relative Permeability—Capillary Pressure Relationship

Both relative permeability and capillary pressure are closely tied to pore size distribution and fluid saturation:

- *Relative permeability*: Refers to how easily a fluid moves through porous rock when more than one fluid is present.
- *Capillary pressure*: The pressure difference at the interface of immiscible fluids inside pores.

As capillary pressure rises, water saturation drops to irreducible levels (Figure 1.31). During this process, relative permeability to water decreases while relative permeability to oil increases. The pore geometry of the rock directly influences both relative permeability and capillary pressure.

- *Permeability influence*: Illustrated in Figure 1.32, an increase in permeability corresponds to a broader pore size distribution. Higher permeability results in lower irreducible water saturation and lower capillary pressure, which reflects improved fluid movement.
- *Production prediction*: The curves in Figure 1.33 reveal how capillary pressure and relative permeability are critical for identifying the productive interval in a reservoir (such as the OWC). These curves can predict changes in production over time as a result of multiphase fluid flow, with permeability variations affecting productivity.

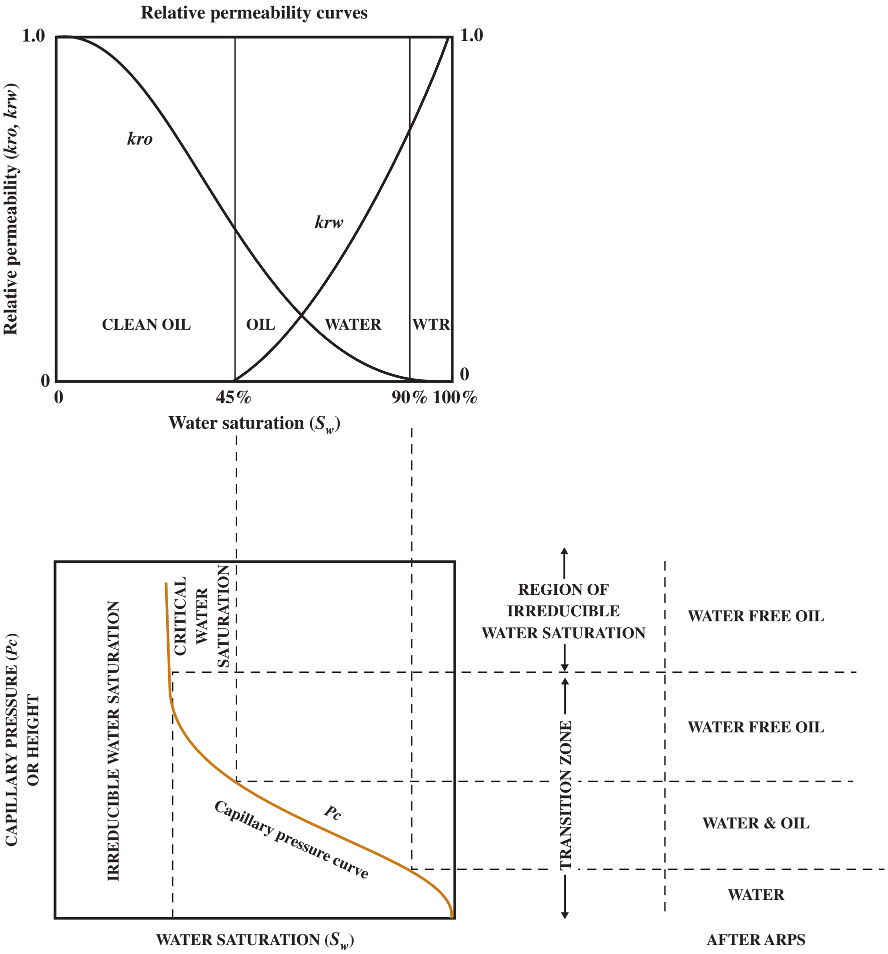


Figure 1.31 Relationship between capillary pressure and relative permeability.

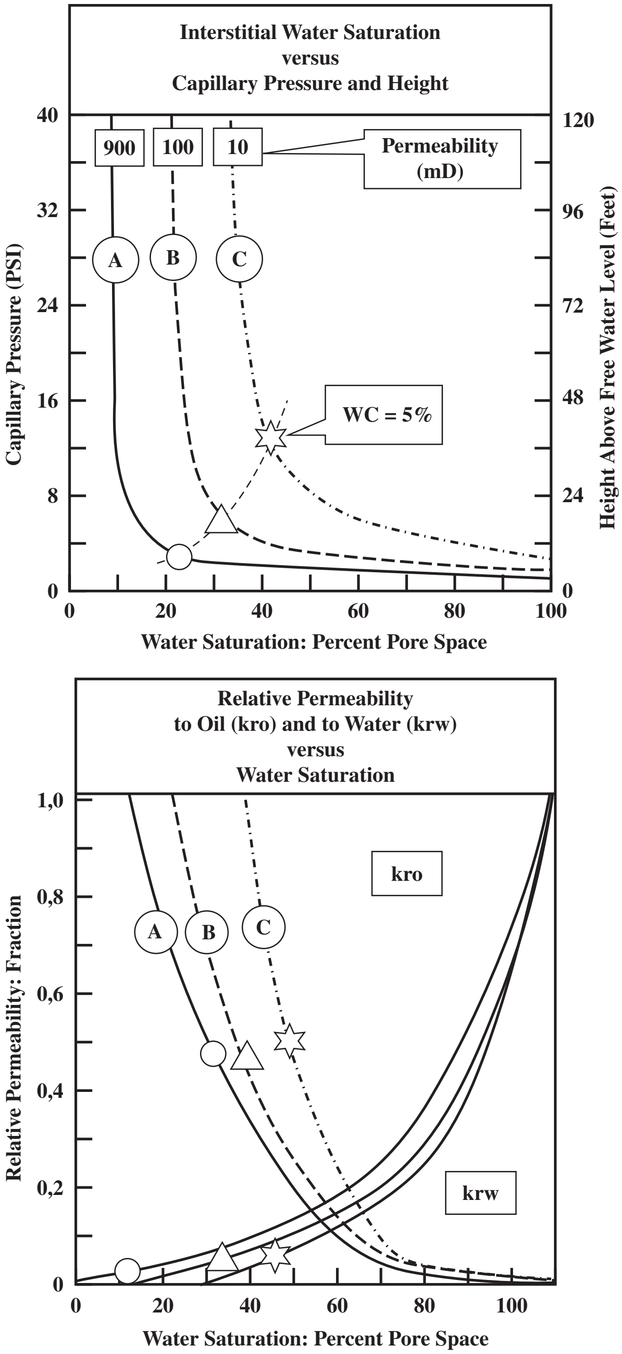


Figure 1.32 Relationship between capillary pressure and relative permeability.

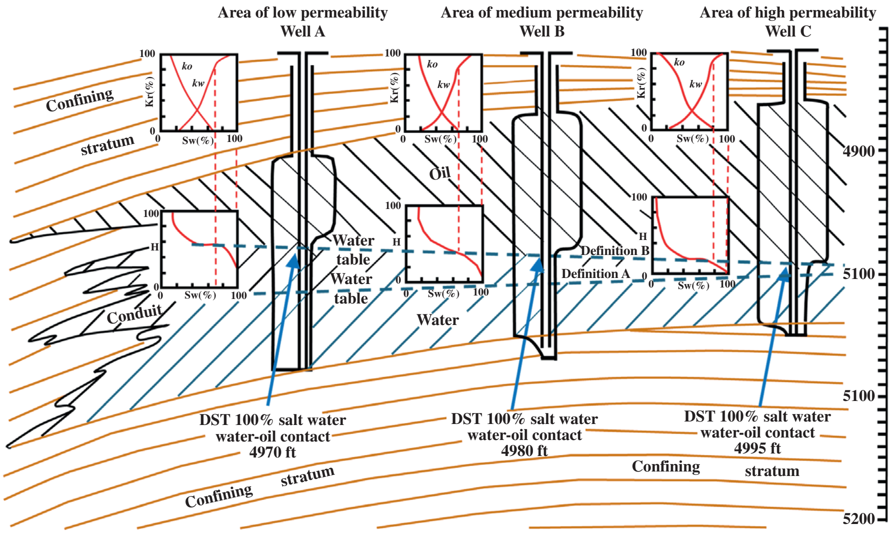


Figure 1.33 Spatial variation of P_c and k_r curves for a reservoir.

1.11 Types of Reservoir Fluids

Reservoir fluids are categorized based on their phase behavior and critical properties, which are essential for effective reservoir management. The five main types of reservoir fluids are:

1. Black Oil
2. Volatile Oil
3. Gas Condensate
4. Wet Gas
5. Dry Gas

1.11.1 Black Oil

- *Phase diagram characteristics*: The phase diagram shows pressure declining at constant temperature (isothermal; Figure 1.34).
- *Undersaturated state* (*Point 1 to Point 2*): The reservoir starts at a pressure much higher than the bubble point, where no gas has evolved. The oil can still absorb more gas.
- *Saturated state* (*Point 2 to Point 3*): Upon reaching the bubble point (Point 2), gas begins to evolve from the oil. Further pressure decline leads to more gas evolution.
- *Production behavior*: In a black oil reservoir, most of the oil phase is recoverable at the surface, with gas separating during production.

Black oil systems are characterized by relatively low gas-to-oil ratios (GOR) and exhibit significant liquid recovery.

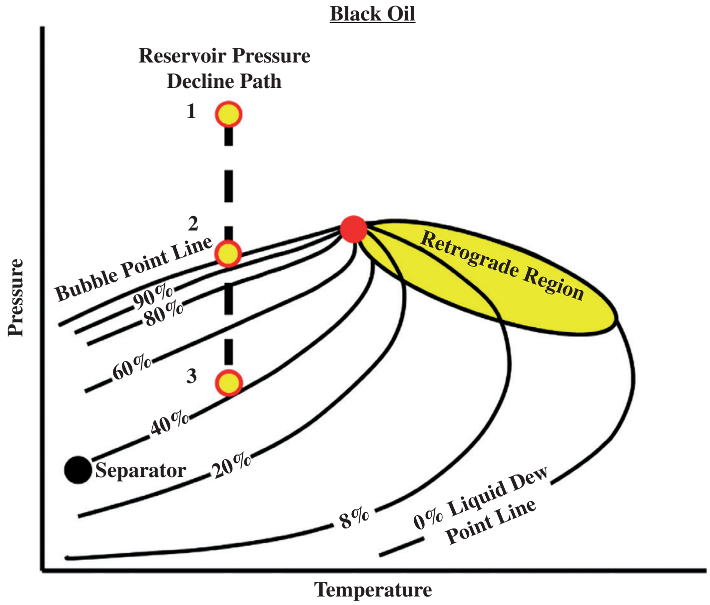


Figure 1.34 Phase diagram of black oil.

1.11.2 Volatile Oil

- *Phase diagram characteristics*: Similar to black oil but with the initial pressure closer to the bubble point. The reservoir contains more light hydrocarbons, making the phase diagram shift up and left (Figure 1.35).
- *Gas evolution*: A small pressure drop below the bubble point releases large amounts of gas. Volatile oil reservoirs produce more gas at the surface than black oils, resulting in less liquid recovery.

1.11.3 Gas Condensate

- *Temperature range*: Between the critical point and cricondentherm.
- *Liquid formation*: As the pressure drops below the dew point, heavier hydrocarbons condense in the reservoir, partially blocking gas flow near the wellbore. Liquid re-vaporizes once pressure falls below the retrograde region (Figure 1.36).

1.11.4 Wet Gas

- *Phase behavior*: The reservoir temperature is above the cricondentherm, meaning no liquid forms in the reservoir. Liquid only forms at surface conditions (Figure 1.37).
- *Production*: The gas stays as a single phase in the reservoir but forms condensate at the surface, hence “wet” gas.

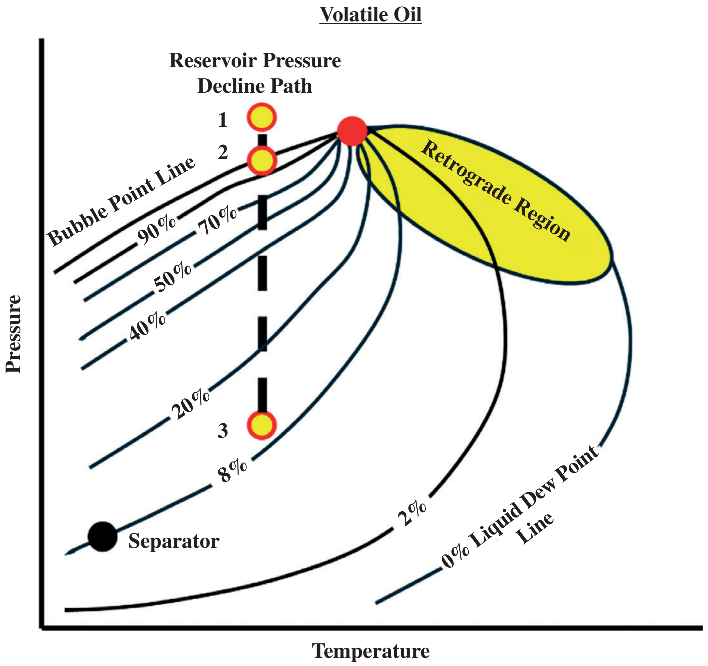


Figure 1.35 Phase diagram of volatile oil.

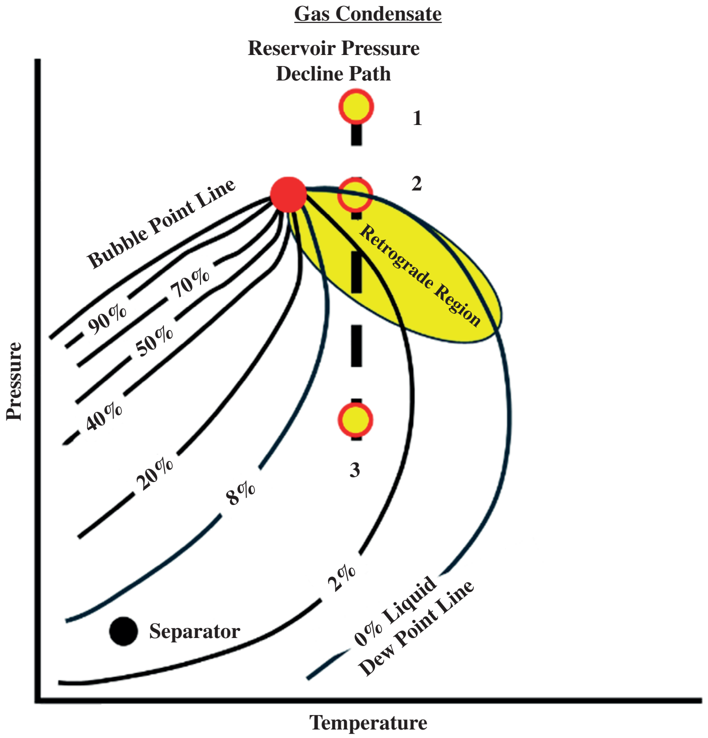


Figure 1.36 Phase diagram of gas condensate.

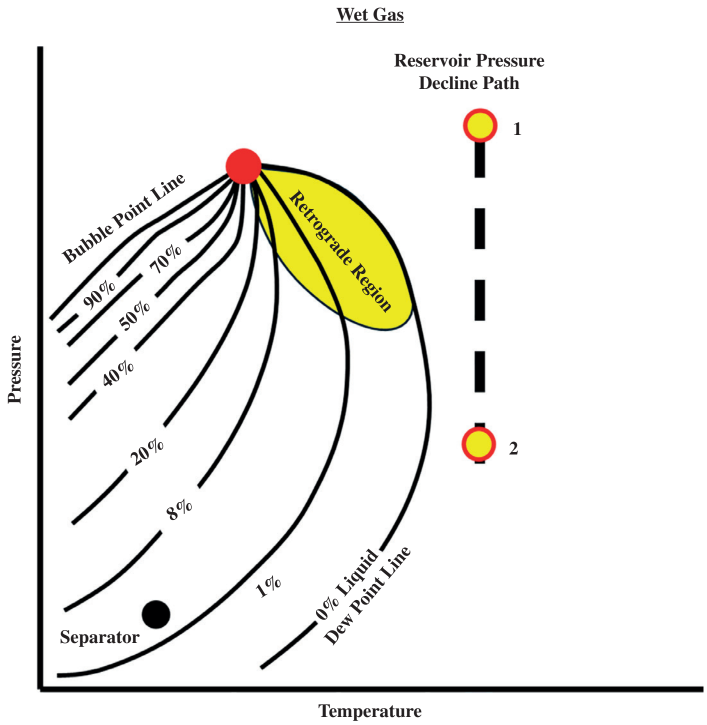


Figure 1.37 Phase diagram of wet gas.

1.11.5 Dry Gas

- *Composition*: Mostly methane, with a simple, condensed phase diagram.
- *Phase Behavior*: Both in the reservoir and at surface conditions, the fluid remains in the gas phase, never entering the two-phase region. Dry gas reservoirs are the easiest to model analytically (Figure 1.38).

For effective enhanced oil recovery (EOR), understanding the phase behavior of volatile oil, gas condensate, wet gas, and dry gas reservoirs is critical. Each fluid type presents unique challenges, from gas evolution in volatile oil reservoirs to condensation issues in gas condensate reservoirs. EOR techniques, such as gas injection, reinjection, and gas cycling, are employed to manage these challenges and maximize recovery.

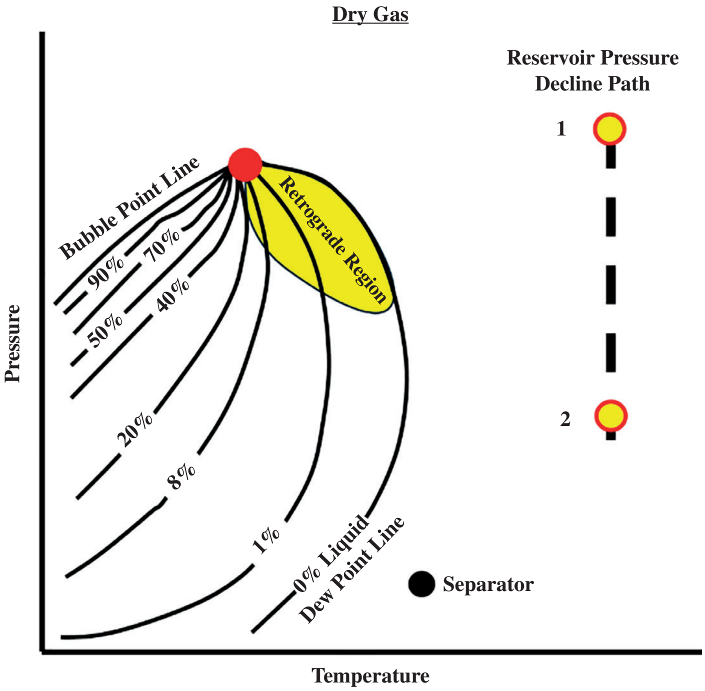


Figure 1.38 Phase diagram of dry gas.

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