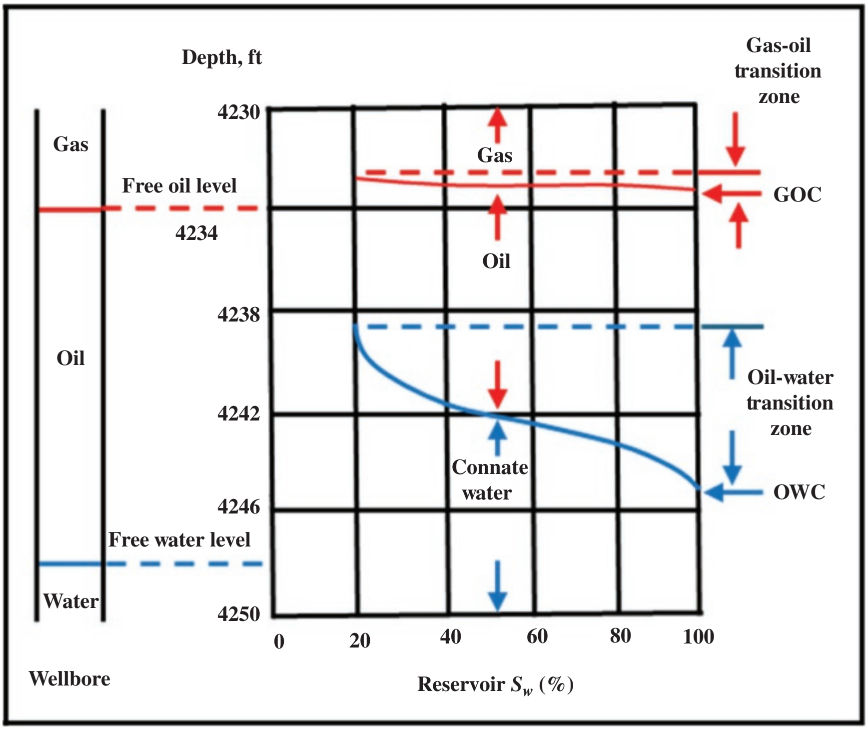


Figure 1.19 Normal initial fluid distribution in a reservoir of uniform permeability and static equilibrium.

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, **$S_g \neq 100\%$** because some of the space is taken up by **irreducible water saturation (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.

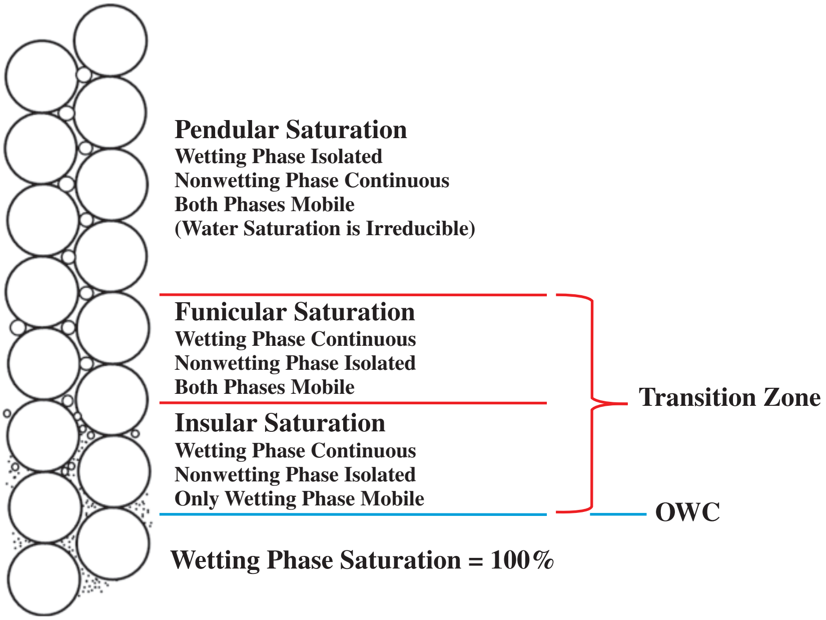


Figure 1.20 Microscopic cross section of OWC and transition zone.

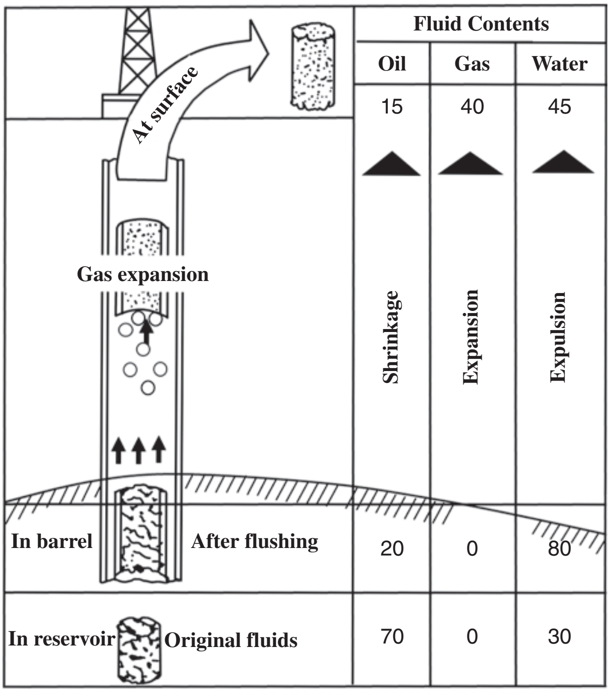


Figure 1.21 Example of saturation changes occurring in the core from *in situ* to surface conditions.

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.

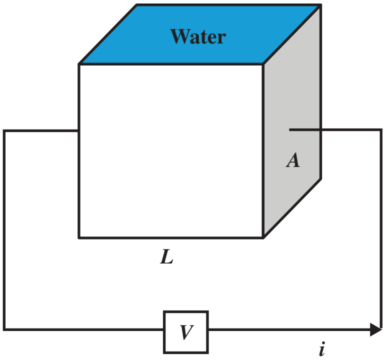


Figure 1.22 Definition of water resistivity.

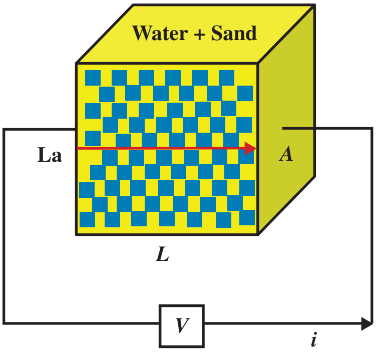


Figure 1.23 Definition of a 100% water-saturated sand.

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:

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

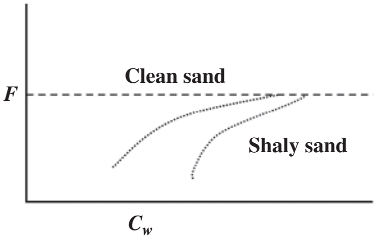
where F is the formation resistivity factor, a proportionality constant that accounts for the increased resistance due to the presence of the rock matrix. Understanding the formation resistivity factor is crucial for accurately interpreting well logs and determining fluid saturation within the formation.

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:

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

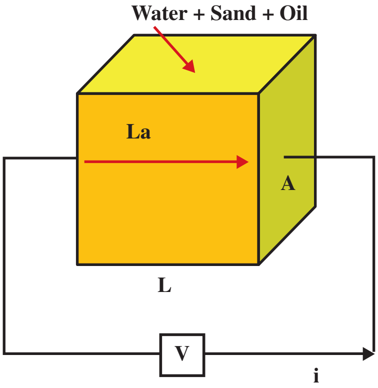


Figure 1.25 Resistance in a hydrocarbon-bearing formation.

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 ($R_t \to \infty$).

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.

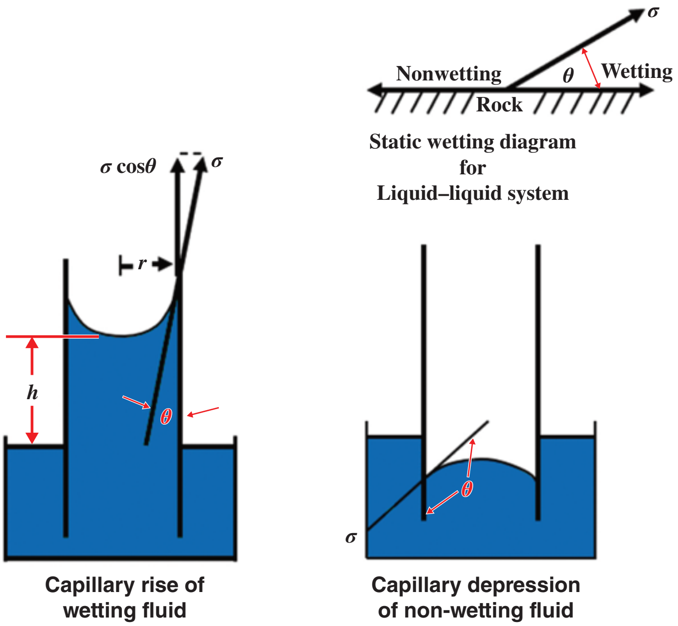


Figure 1.26 Capillary tubes in wetting and nonwetting fluids.

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.

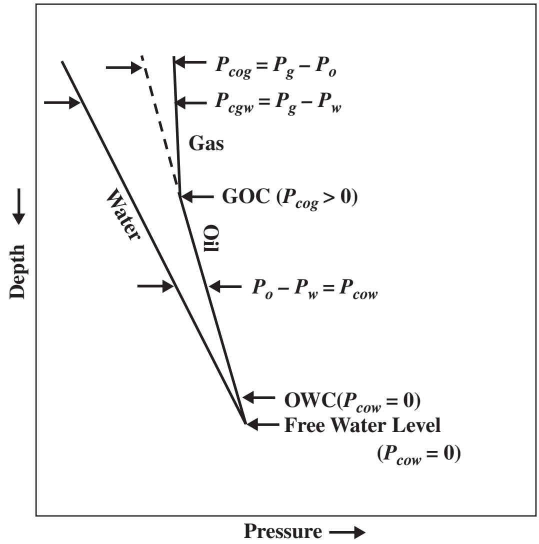


Figure 1.27 Capillary pressure in reservoirs.

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).

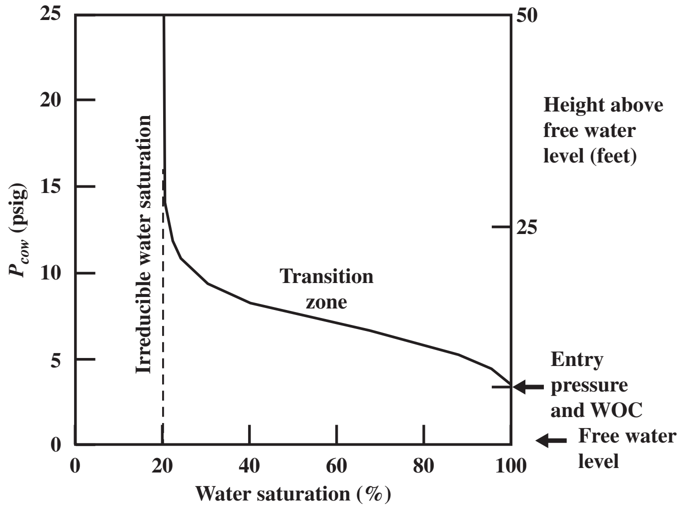


Figure 1.28 Conventional capillary pressure curve.

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}.

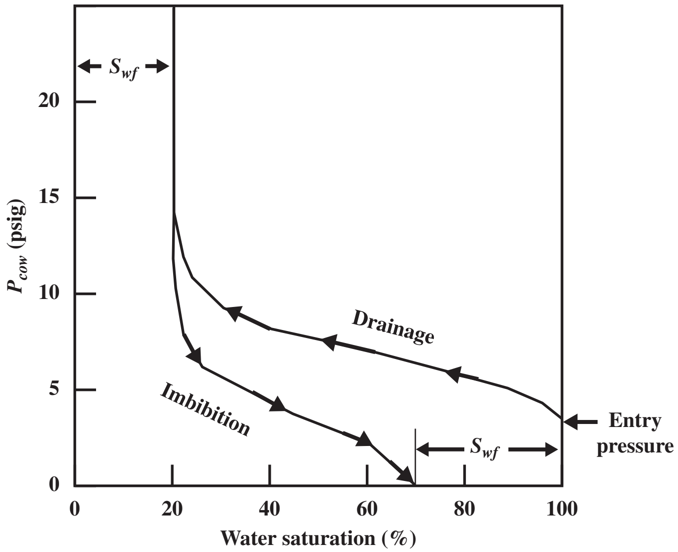


Figure 1.29 Imbibition and drainage capillary pressure curves illustrating hysteresis.

- *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.

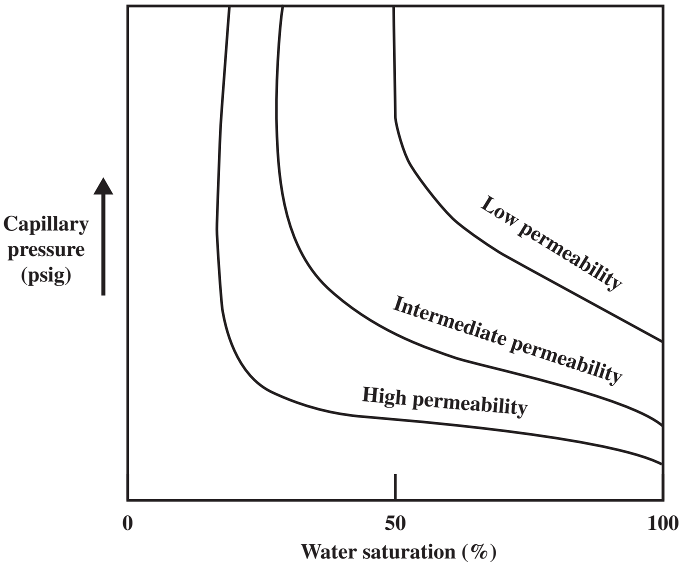


Figure 1.30 Effect of permeability on capillary pressure.

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.

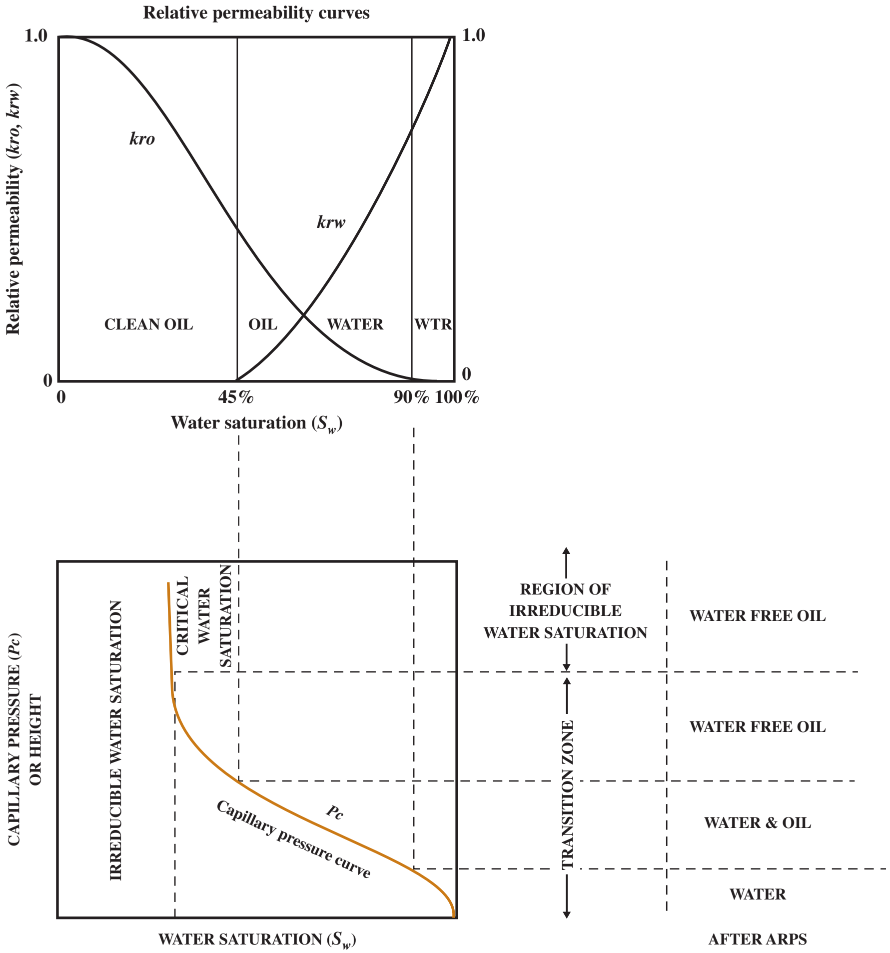


Figure 1.31 Relationship between capillary pressure and relative permeability.

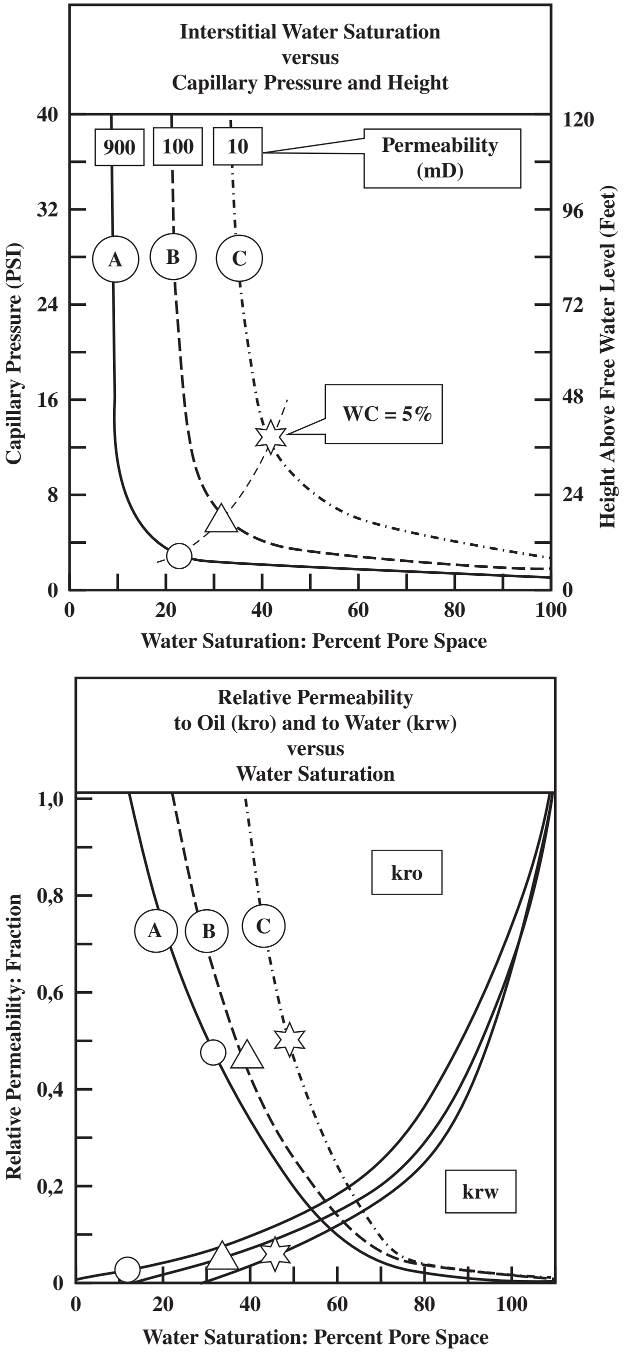


Figure 1.32 Relationship between capillary pressure and relative permeability.

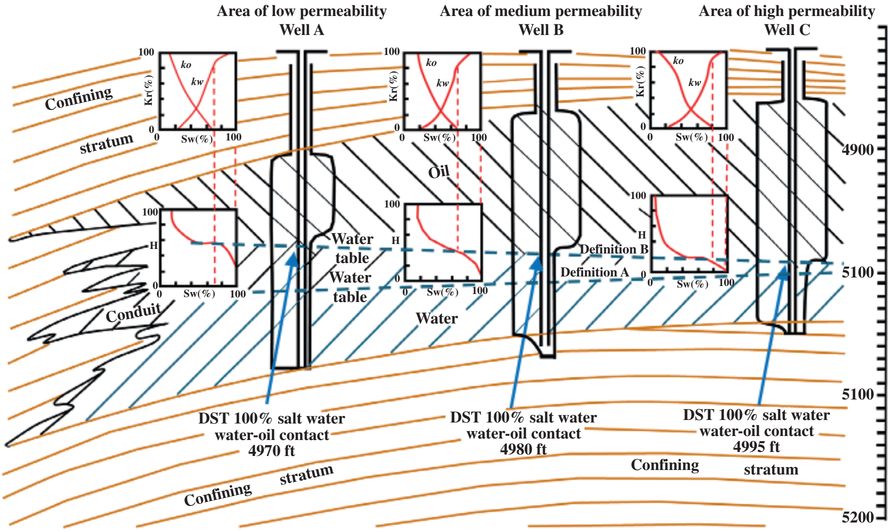


Figure 1.33 Spatial variation of P_c and k_r curves for a reservoir.

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.

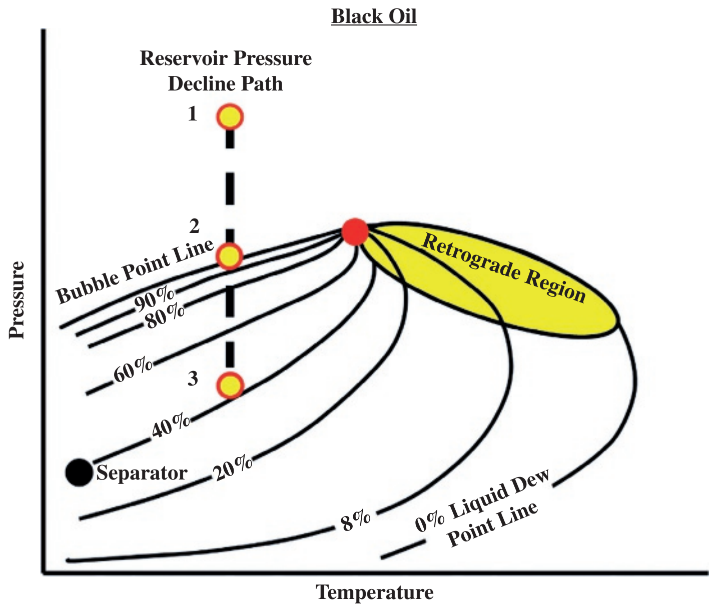


Figure 1.34 Phase diagram of black oil.

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.

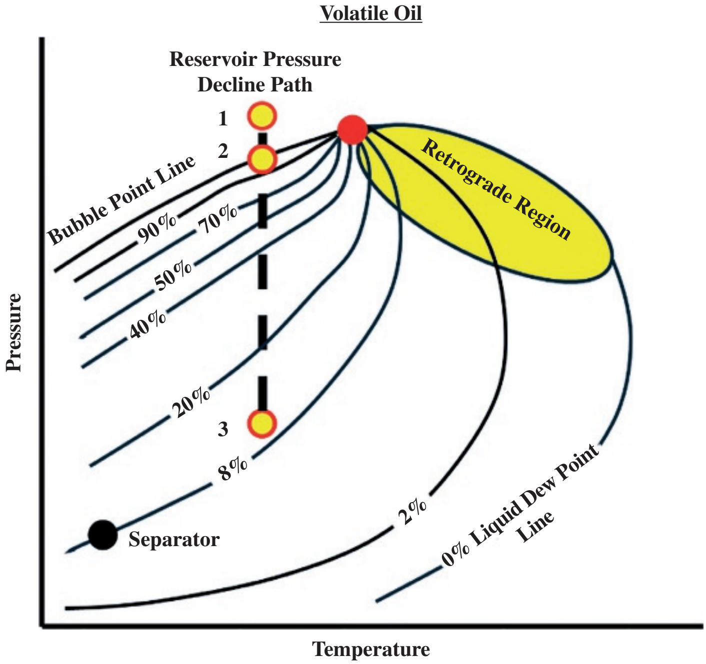


Figure 1.35 Phase diagram of volatile oil.

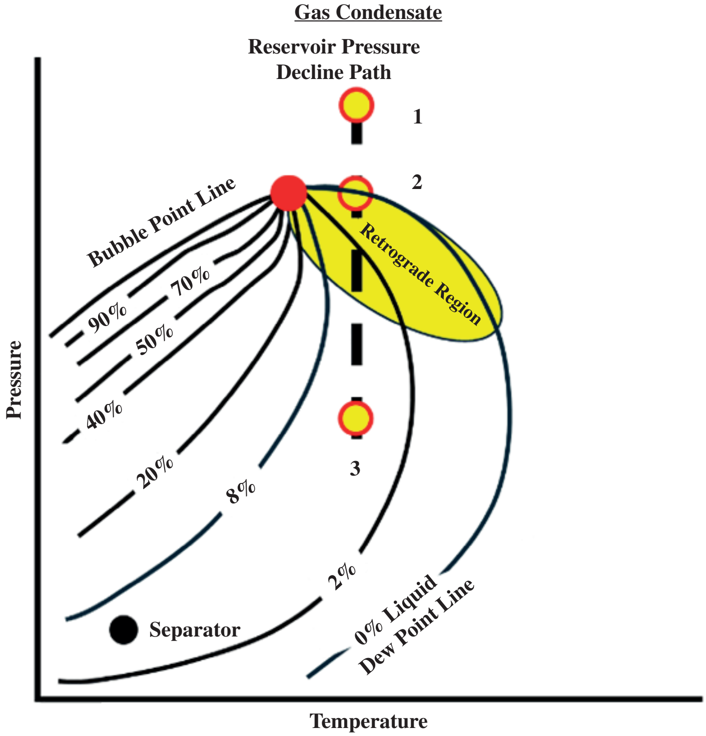


Figure 1.36 Phase diagram of gas condensate.

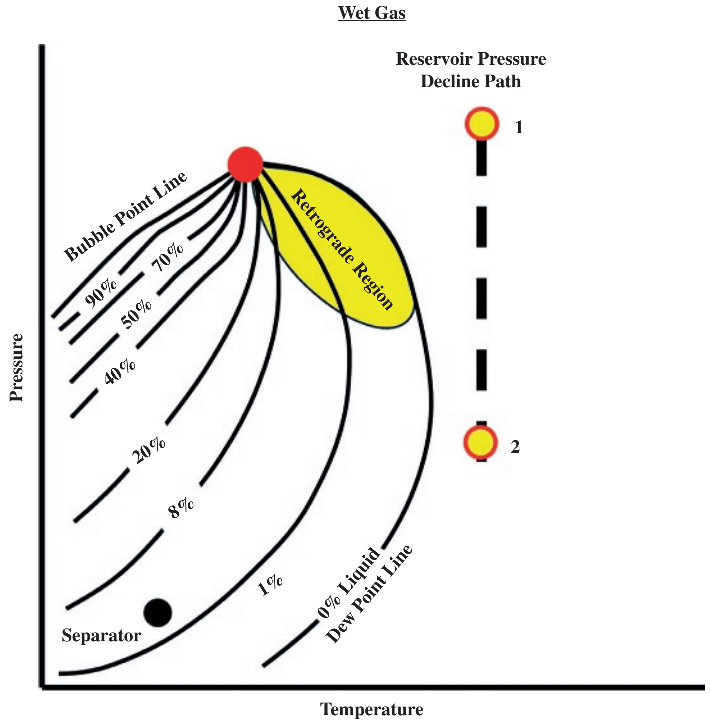


Figure 1.37 Phase diagram of wet gas.

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.

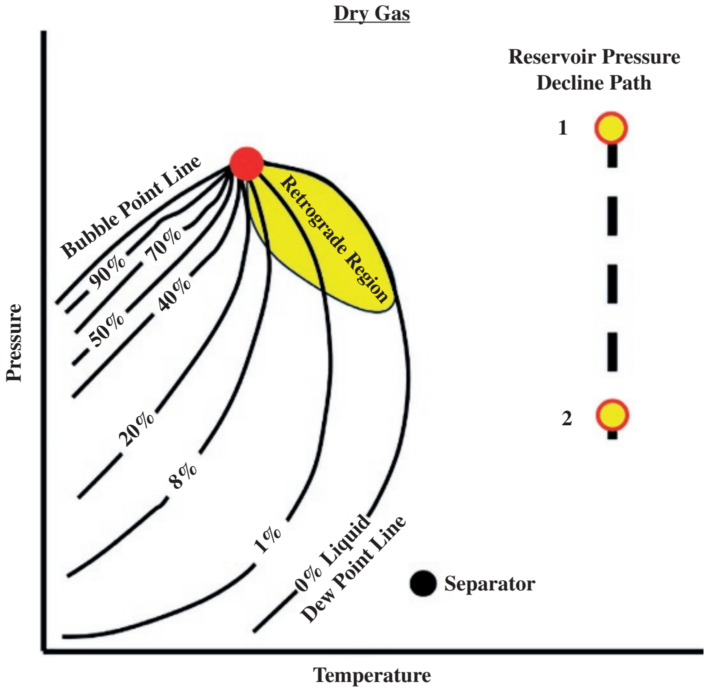


Figure 1.38 Phase diagram of dry gas.

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