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Chapter One

Classification of Hydrocarbon Reservoir

Naturally occurring hydrocarbon systems found in petroleum reservoirs are mixtures of organic compounds that exhibit multiphase behavior over wide ranges of pressures and temperatures. These hydrocarbon accumulations may occur in the gaseous state, the liquid state, the solid state, or in various combinations of gas, liquid, and solid. These differences in phase behavior, coupled with the physical properties of reservoir rock that determine the relative ease with which gas and liquid are transmitted or retained, result in many diverse types of hydrocarbon reservoirs with complex behaviors. Frequently, petroleum engineers have the task to study the behavior and characteristics of a petroleum reservoir and to determine the course of future development and production that would maximize the profit.

CLASSIFICATION OF RESERVOIRS AND RESERVOIR FLUIDS

Petroleum reservoirs are broadly classified as oil or gas reservoirs. These broad classifications are further subdivided depending on:
• The composition of the reservoir hydrocarbon mixture
• Initial reservoir pressure and temperature
• Pressure and temperature of the surface produce.

![Figure 1-1. Typical p-T diagram for a multicomponent system.](image-url)
Figure 1-1 shows a typical pressure-temperature diagram of a multicomponent system with a specific overall composition. Although a different hydrocarbon system would have a different phase diagram, the general configuration is similar. These multicomponent pressure-temperature diagrams are essentially used to:

- Classify reservoirs
- Classify the naturally occurring hydrocarbon systems
- Describe the phase behavior of the reservoir fluid

To fully understand the significance of the pressure-temperature diagrams, it is necessary to identify and define the following key points on these diagrams:

- **Cricondentherm** ($T_{ct}$)—The Cricondentherm is defined as the maximum temperature above which liquid cannot be formed regardless of pressure (point E) (The maximum temperature at which condensation takes place at dew point curve). The corresponding pressure is termed the Cricondentherm pressure $p_{ct}$.

- **Cricondenbar** ($p_{cb}$)—The Cricondenbar is the maximum pressure above which no gas can be formed regardless of temperature (point D). The corresponding temperature is called the Cricondenbar temperature $T_{cb}$.

- **Critical point**—The critical point for a multicomponent mixture is referred to as the state of pressure and temperature at which all intensive properties of the gas and liquid
phases are equal (point C). At the critical point, the corresponding pressure and temperature are called the critical pressure $p_c$ and critical temperature $T_c$ of the mixture.

- **Phase envelope (two-phase region)**—The region enclosed by the bubble-point curve and the dew-point curve (line BCA), wherein gas and liquid coexist in equilibrium, is identified as the phase envelope of the hydrocarbon system.

- **Quality lines**—The dashed lines within the phase diagram are called quality lines. They describe the pressure and temperature conditions for equal volumes of liquids. Note that the quality lines converge at the critical point (point C).

- **Bubble-point curve**—The bubble-point curve (line BC) is defined as the line separating the liquid-phase region from the two-phase region.

- **Dew-point curve**—The dew-point curve (line AC) is defined as the line separating the vapor-phase region from the two-phase region.

In general, reservoirs are conveniently classified on the basis of the location of the point representing the initial reservoir pressure $p_i$ and temperature $T$ with respect to the pressure-temperature diagram of the reservoir fluid. Accordingly, reservoirs can be classified into basically two types. These are:

- **Oil reservoirs**—If the reservoir temperature $T$ is less than the critical temperature $T_c$ of the reservoir fluid, the reservoir is classified as an oil reservoir.

- **Gas reservoirs**—If the reservoir temperature is greater than the critical temperature of the hydrocarbon fluid, the reservoir is considered a gas reservoir.

**Oil Reservoirs**

Depending upon initial reservoir pressure $p_i$, oil reservoirs can be subclassified into the following categories:

1. **Undersaturated oil reservoir**. If the initial reservoir pressure $p_i$ (as represented by point 1 on Figure 1-1), is greater than the bubble-point pressure $p_b$ of the reservoir fluid, the reservoir is labeled an undersaturated oil reservoir.
2. **Saturated oil reservoir.** When the initial reservoir pressure is equal to the bubble-point pressure of the reservoir fluid, as shown on Figure 1-1 by point 2, the reservoir is called a saturated oil reservoir.

3. **Gas-cap reservoir.** If the initial reservoir pressure is below the bubble point pressure of the reservoir fluid, as indicated by point 3 on Figure 1-1, the reservoir is termed a gas-cap or two-phase reservoir, in which the gas or vapor phase is underlain by an oil phase. The appropriate quality line gives the ratio of the gas-cap volume to reservoir oil volume. Crude oils cover a wide range in physical properties and chemical compositions, and it is often important to be able to group them into broad categories of related oils. In general, crude oils are commonly classified into the following types:

- Ordinary black oil
- Low-shrinkage crude oil
- High-shrinkage (volatile) crude oil
- Near-critical crude oil

The above classifications are essentially based upon the properties exhibited by the crude oil, including physical properties, composition, gas-oil ratio, appearance, and pressure-temperature phase diagrams.

**Notes:**

**Standard Conditions**

- \( P_{s,c} = 1.013 \text{ bara (or 14.7 psia)} \)
- \( T_{s,c} = 15.6 ^\circ \text{C (or 60 } ^\circ \text{F)} \)

**Formation Volume Factor**

\[
Bo = \frac{V_0}{V_{\text{std ref}}} = \frac{\text{Volume of oil in reservoir P, T conditions}}{\text{Volume of stock tank oil in standard conditions}}
\]

**Solution gas/oil ratio (Rs)**

\[
Rs = \frac{V_{g \text{ std}}}{V_{\text{std ref}}} = \frac{\text{Volume of gas in standard conditions}}{\text{Volume of oil in standard conditions}}
\]

Rs quantifies the amount of gaseous components which are dissolved in the oil at reservoir conditions.
1. **Ordinary black oil.** It should be noted that quality lines, which are approximately equally spaced, characterize this black oil phase diagram. Following the pressure reduction path as indicated by the vertical line EF on Figure 1-2, the liquid shrinkage curve, as shown in Figure 1-3, is prepared by plotting the liquid volume percent as a function of pressure. The liquid shrinkage curve approximates a straight line except at very low pressures. When produced, ordinary black oils usually yield gas-oil ratios between 200 and 700 scf/STB and oil gravities of 15° to 40° API. The stock tank oil is usually brown to dark green in color.
**Low-shrinkage oil**

The diagram is characterized by quality lines that are closely spaced near the dew-point curve. The other associated properties of this type of crude oil are:

- Oil formation volume factor less than 1.2 bbl/STB
- Gas-oil ratio less than 200 scf/STB
- Oil gravity less than 35° API
- Black or deeply colored

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**Figure 1-4.** A typical phase diagram for a low-shrinkage oil.

**Figure 1-5.** Oil-shrinkage curve for low-shrinkage oil.
3. **Volatile crude oil.** Note that the quality lines are close together near the bubble-point and are more widely spaced at lower pressures. This type of crude oil is commonly characterized by a high liquid shrinkage immediately below the bubble-point as shown in Figure 1-7.

The other characteristic properties of this oil include:
- Oil formation volume factor less than 2 bbl/STB
- Gas-oil ratios between 2,000 and 3,200 scf/STB
- Oil gravities between 45° and 55° API
- Lower liquid recovery of separator conditions as indicated by point G on Figure 1-6
- Greenish to orange in color

Another characteristic of volatile oil reservoirs is that the API gravity of the stock-tank liquid will increase in the later life of the reservoirs.

![Figure 1-6. A typical p-T diagram for a volatile crude oil.](image)

![Figure 1-7. A typical liquid-shrinkage curve for a volatile crude oil.](image)
4. **Near-critical crude oil.** If the reservoir temperature $T$ is near the critical temperature $T_c$ of the hydrocarbon system, as shown in Figure 1-8, the hydrocarbon mixture is identified as a near-critical crude oil. Because all the quality lines converge at the critical point, an isothermal pressure drop (as shown by the vertical line EF in Figure 1-8) may shrink the crude oil from 100% of the hydrocarbon pore volume at the bubble-point to 55% or less at a pressure 10 to 50 psi below the bubblepoint. The shrinkage characteristic behavior of the near-critical crude oil is shown in Figure 1-9. The near-critical crude oil is characterized by a high GOR in excess of 3,000 scf/STB with an oil formation volume factor of 2.0 bbl/STB or higher. The compositions of near-critical oils are usually characterized by 12.5 to 20 mol% heptanes-plus, 35% or more of ethane through hexanes, and the remainder methane.

![Figure 1-8. A schematic phase diagram for the near-critical crude oil.](image-url)
Figure 1-9. A typical liquid-shrinkage curve for the near-critical crude oil.

Figure 1-10. Liquid shrinkage for crude oil systems.
Gas Reservoirs

In general, if the reservoir temperature is above the critical temperature of the hydrocarbon system, the reservoir is classified as a natural gas reservoir. On the basis of their phase diagrams and the prevailing reservoir conditions, natural gases can be classified into 3 categories:

- Retrograde gas-condensate
- Wet gas
- Dry gas

Retrograde gas-condensate reservoir

If the reservoir temperature $T$ lies between the critical temperature $T_c$ and cricondentherm $T_{ct}$ of the reservoir fluid, the reservoir is classified as a retrograde gas-condensate reservoir.

- the gas-oil ratio for a condensate system increases with time due to the liquid dropout and the loss of heavy components in the liquid.
- Condensate gravity above 50° API
- Stock-tank liquid is usually water-white or slightly colored

Figure 1-11. A typical phase diagram of a retrograde system.
**Wet-gas reservoir**

Temperature of wet-gas reservoir is above the cricondentherm of the hydrocarbon mixture. Because the reservoir temperature exceeds the cricondentherm of the hydrocarbon system, the reservoir fluid will always remain in the vapor phase region as the reservoir is depleted isothermally, along the vertical line A-B. Wet-gas reservoirs are characterized by the following properties:

- Gas oil ratios between 60,000 to 100,000 scf/STB
- Stock-tank oil gravity above 60° API
- Liquid is water-white in color
- Separator conditions, i.e., separator pressure and temperature, lie within the two-phase region

**Dry-gas reservoir**

The hydrocarbon mixture exists as a gas both in the reservoir and in the surface facilities. Usually a system having a gas-oil ratio greater than 100,000 scf/STB is considered to be a dry gas.

*Figure 1-16. Phase diagram for a dry gas. (After Clark, N.J. Elements of Petroleum Reservoirs, SPE, 1969.)*
Fluid Distribution

Two or three types of reservoir fluid are expected to exist in the oil and gas formations:

1- **Formation water (Brine):**

   The water originally existed in the porous media. There are no oil or gas formations without this water. The percentage of the pore space volume equipped by formation water is called water saturation. Connate (interstitial) water saturation (Swc) is the amount of the water that is not reducible. It is important primarily because it reduces the amount of space available between oil and gas. It is generally not uniformly distributed throughout the reservoir but varies with permeability, lithology, and height above the free water table.

2- **Oil:**

   Liquid phase hydrocarbon mixture already accumulated in the formation. The volumetric percentage of the oil in the pore space is called oil saturation. Three types of oil may exist in the formation.
   - Movable oil represents the amount of oil that can be produced (Som).
   - Critical oil represents free oil that cannot move if the oil saturation is less than the critical water saturation (swc).
   - Residual oil which cannot be produced (Sor).

3- **Gas:**

   Gas phase hydrocarbon mixture already accumulated in the formation. It can be found alone with the formation water, the reservoir in this case is called Natural gas reservoir. If the free gas is trapped above the oil, the reservoir is called gas cap reservoir. The volumetric percentage of the gas in the pore space is called gas saturation (Sg). Critical gas saturation refers to the amount of the gas that is immovable (Sgc). Soluble gas refers to the gas that is dissolved in the oil and liberates when the reservoir pressure moves down the bubble point pressure.

Notes:
Som: saturation oil movable
Sor: secondary oil residual
The expansion mechanisms oil reservoirs

There are several ways in which oil can be displaced and produced from a reservoir, and these may be termed mechanisms or “drives”:

- Expansion of under saturated oil above the bubble point.
- Expansion of rock and of connate water.
- Expansion of gas released from solution in the oil below the bubble point.
- Invasion of the original oil bearing reservoir by the expansion of the gas from a free gas cap.
- Invasion of the original oil bearing reservoir by the expansion of the water from an adjacent or underlying aquifer.

The expansion mechanisms are not usually considered separately, and the three principal categories of reservoir are:
1. Solution gas drive (or depletion drive) reservoirs.
2. Gas cap expansion drive reservoirs.
3. Water drive reservoirs.

1. Solution Gas derive or depletion derive
Note: 1-(It do not intially contain free gas but developed free gas on pressure depletion) at preessure falls below bubble point (blak & voliatile oil reservoir).  
2- The performance of it used as benchmark to compare other producing mechanisms.

3- Gas cap drive reservoir

Notes:  
1- It is found with segregated gas zone overlying an oil column.  
2- The gas gaps usually contain connate water residual oil.
3- The recovery depends mainly on their size and on the vertical permeability.

4- Water drive reservoir
Notes:
1- Bounded by aquifers.
2- Pressure decreases during pressure depletion.
3- Can be injection water as recovery.

5- Combination drive reservoir
Hydrocarbon Traps

A trap forms when the buoyancy forces driving the upward migration of hydrocarbons through a permeable rock cannot overcome the capillary forces of a sealing medium. The timing of trap formation relative to that of petroleum generation and migration is crucial to ensuring a reservoir can form.

- Structural traps
- Stratigraphic traps (hold oils and gas because the earth has been bent and deformed in some way).
- Combination traps

**Structural traps** are caused by structural features. They are usually formed as a result of tectonics. Stratigraphic traps are usually caused by changes in rock quality. Combination traps that combine more than one type of trap are common in petroleum reservoirs. Other types of traps (such as hydrodynamic traps) are usually less common.

Fig. Structural Hydrocarbon Traps
**Hydrocarbon Traps - Dome**

The dome above shows gravity separation of fluids. Shale comprises the upper and lower confining beds.

![Diagram of hydrocarbon traps - dome](image)

**Fault Trap**

In this normal fault trap, oil-bearing sandstone is juxtaposed against impervious shale.

![Diagram of fault trap](image)

**Stratigraphic Hydrocarbon Traps**

Stratigraphic hydrocarbon traps occur where reservoir facies pinch into impervious rock such as shale, or where they have been truncated by erosion and capped by impervious layers above an unconformity.
**Other Traps**

In hydrodynamic traps, the hydrocarbon is trapped by the action of water movements. Tilted contacts are common in this case. The water usually comes from a source such as rain falls or rivers.

*Note: Hydrodynamic traps are a far less common type of trap. They are caused by the differences in water pressure, that are associated with water flow, creating a tilt of the hydrocarbon-water contact.*