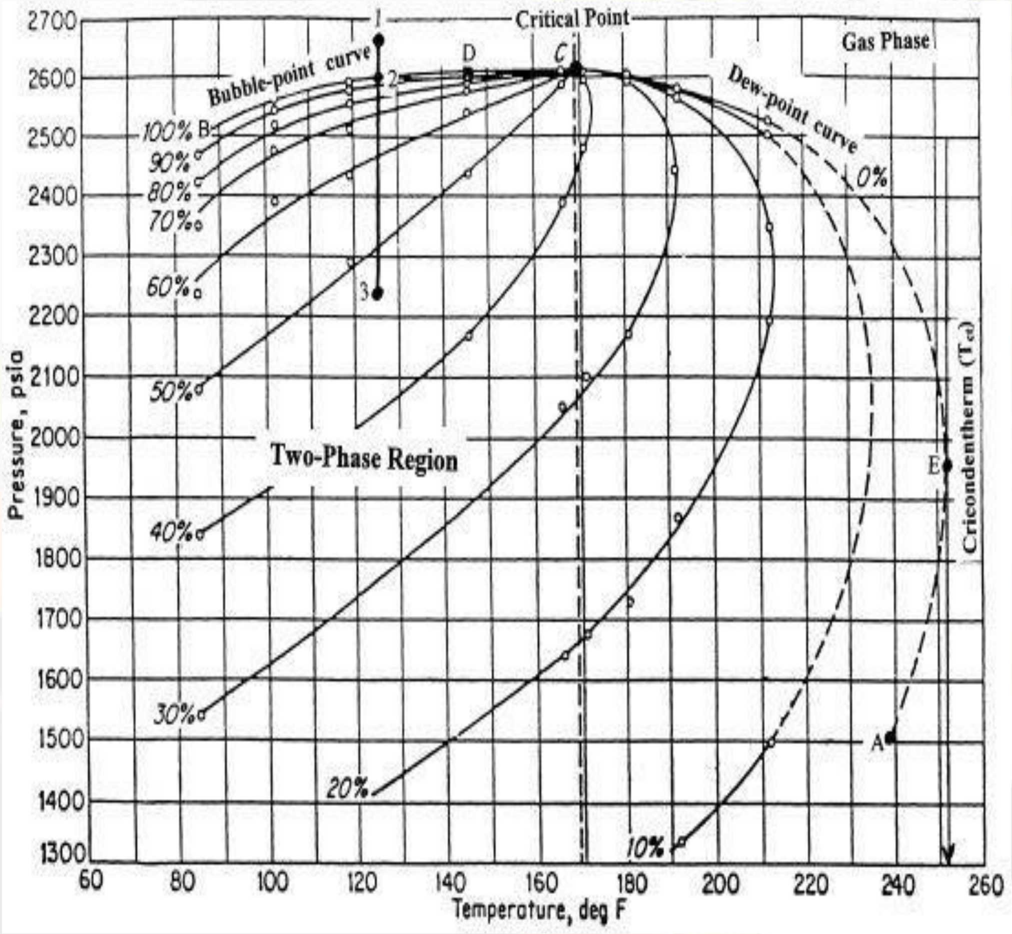
# Classification of Petroleum Reservoirs




Petroleum reservoirs are broadly classified as oil or gas reservoirs. These broad classifications are further subdivided depending on:

1. The composition of the reservoir hydrocarbon mixture.
2. Initial reservoir pressure and temperature.
3. Pressure and temperature of the surface production.
4. Location of the reservoir temperature with respect to the critical temperature and the cricondentherm.

According to the initial reservoir pressure *pi* and temperature *T* of the reservoir with respect to the *p*/*T* diagram of the reservoir fluid, reservoirs can be classified into two types:

- ***Oil reservoirs*** If the reservoir temperature, *T*, is less than the critical temperature, *Tc*, 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

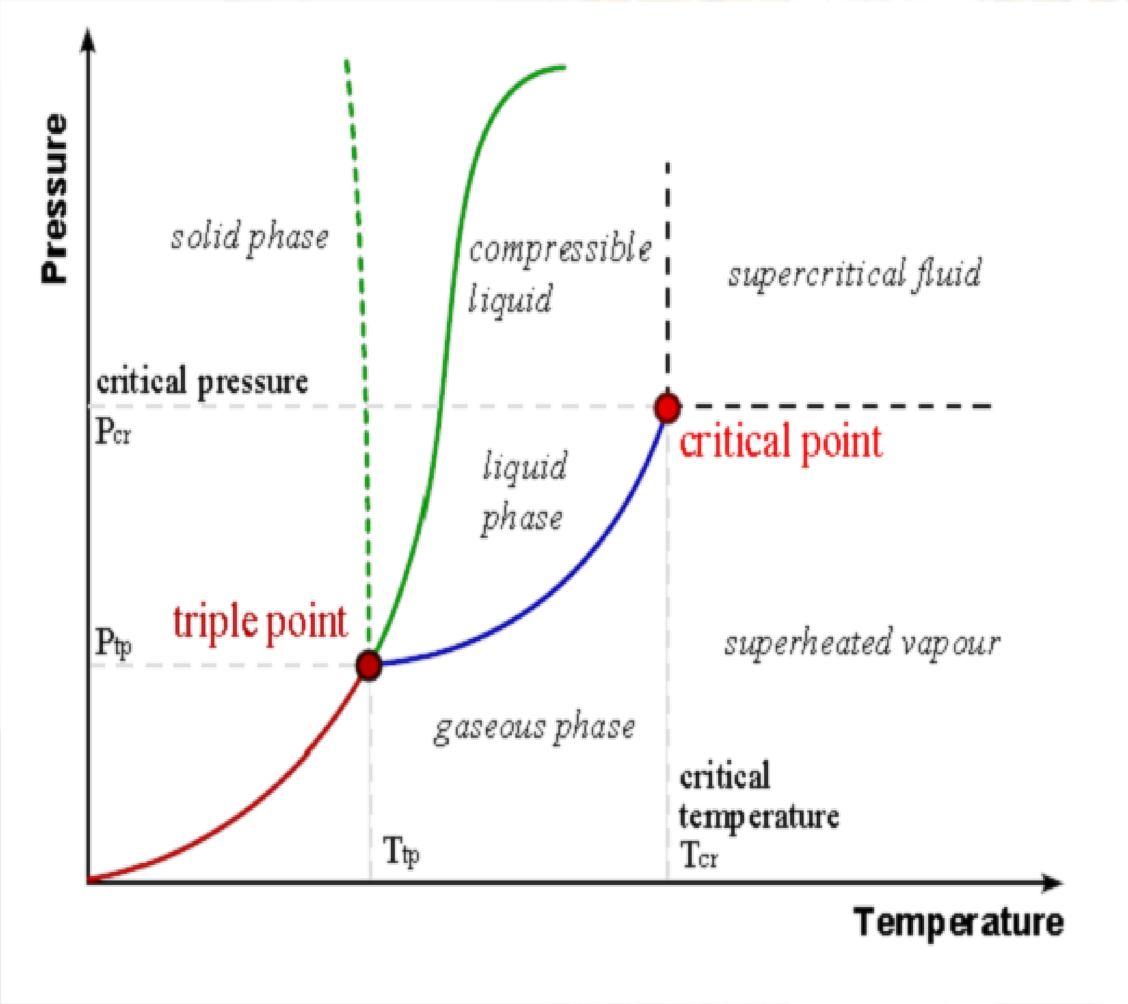
- Contain mainly oil with or without free gas (gas cap).
- Depending on initial reservoir pressure, *pi*, oil reservoirs can be subclassified into the following categories:

- Oil reservoir
  - under saturated
  - Saturated
  - Gas cap

***Note:***

- Under saturated Oil Reservoir (Pres > Pb) - no free gas exists until the reservoir pressure falls below the bubble point pressure.
- Saturated Oil Reservoir (Pres < Pb) – free gas (gas cap) exists in the reservoir.
- Gas-cap reservoir. If the initial reservoir pressure is below the bubble point pressure of the reservoir fluid, the reservoir is termed a gas-cap or two-phase reservoir,

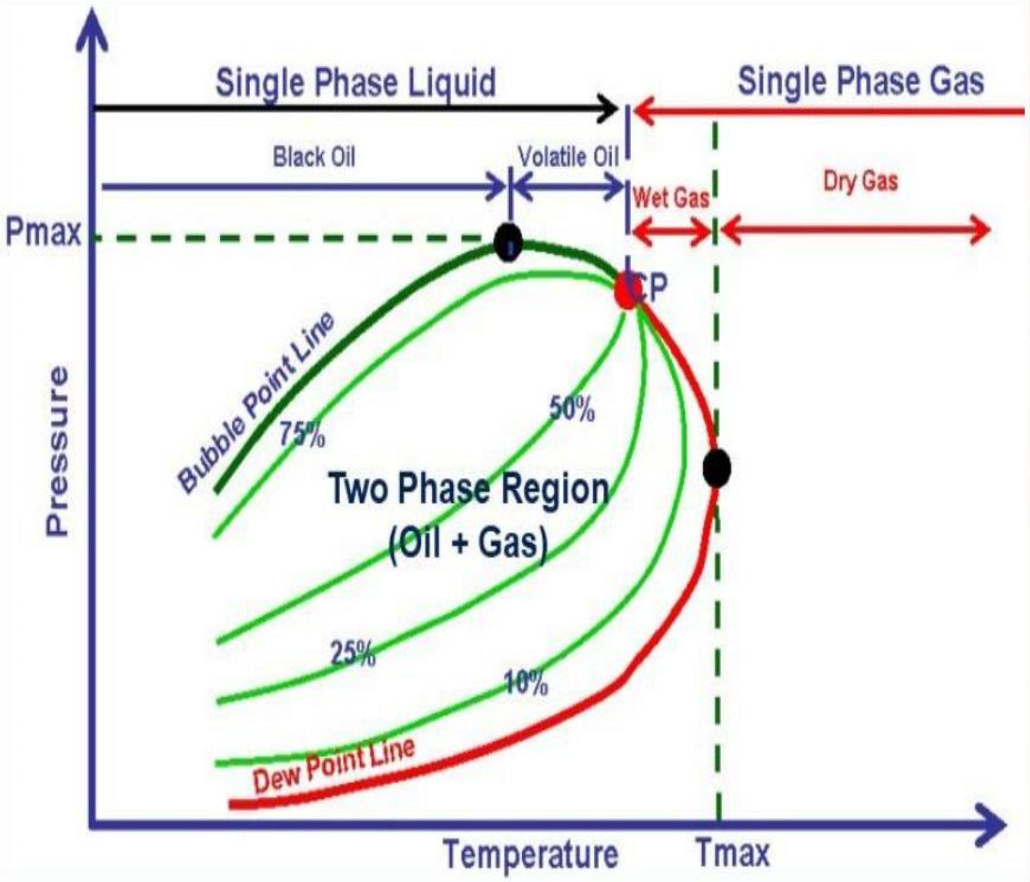
# PHASE DIAGRAM OF A PURE COMPONENT



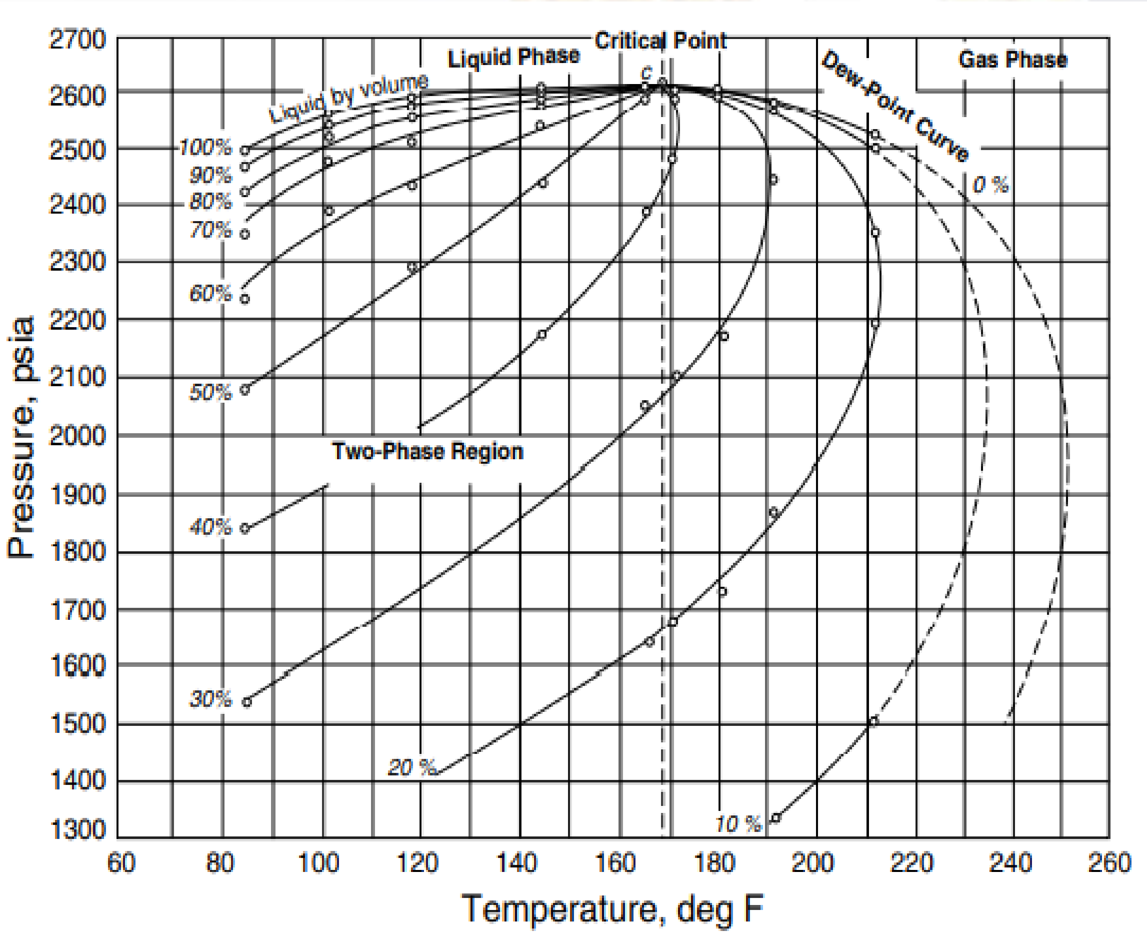

- Line TC is called ***the vapor – pressure line*** (separate the pressure – temperature conditions for liquid substance from gas)
- ***Critical point*** - the upper limit of the TC curve is called the c**ritical point** indicated by point C. the pressure and temperature represented at this point are known as the **critical pressure, Pc**, and **critical temperature, Tc**.

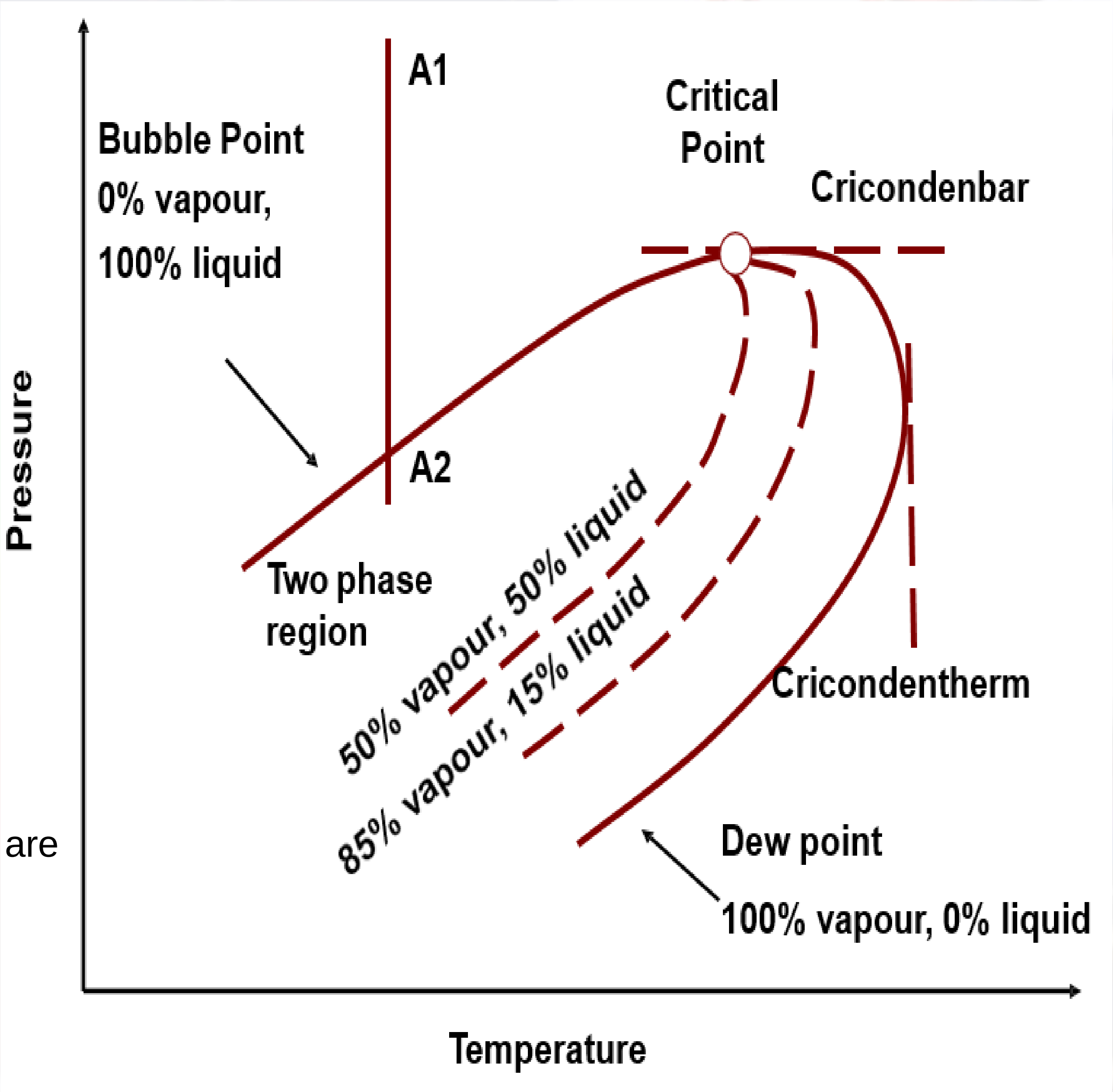
- ***The critical point*** represents the maximum pressure and temperature at which a pure component can form coexisting phases.
- Another classical definition of ***critical point*** is the state of pressure and temperature at which the intensive properties of the gas and the liquid phases are continuously identical.
- **Triple Point *(T)*** is represents the pressure and temperature conditions at which all three phases (gas, liquid, and solid) of a component coexist under equilibrium.
- **The melting point line** is nearly vertical line above the triple point, which separates the solid conditions from liquid conditions .

# PHASE BEHAVIOR OF TWO-COMPONENT OR BINARY SYSTEMS




- In a binary system, there is a broad region in which the two phases coexist in equilibrium. This broad region is commonly referred to as the ***phase envelope***, ***saturation envelope***, or simply, the ***two-phase region***
- The various important features of the phase envelope of a binary system include ***critical point***, **bubble point**, **dew point**, ***bubble-point and dew-point curves***, ***cricondenbar***, ***cricondentherm***
- ***Critical point*** : it is the point at which all properties of the liquid and gas become identical.
- ***Bubble-Point and Dew-Point Curves*** The bubble-point and the dew-point curves are the outermost boundaries of the phase envelope lying on the left-hand side and the right-hand side of the critical point, respectively.
- The bubble-point and the dew-point curves meet at the critical point.
- ***Cricondentherm***— is defined as the maximum temperature (highest temperature) on the saturation envelope , above which liquid cannot be formed regardless of pressure .
- ***Cricondenbar*** is the highest pressure on the saturated envelope (i.e. the maximum pressure above which no gas can be formed regardless of temperature.
- ***Phase envelope (two-phase region)*****—**The region enclosed by the bubble-point curve and the dew-point curve, wherein gas and liquid coexist in equilibrium, is identified as the phase envelope of the hydrocarbon system
- ***Bubble-point curve***—The bubble-point curve is defined as the line separating the liquid-phase region from the two-phase region. • Dew-point curve—The dew-point curve is defined as the line separating the vapor-phase region from the two-phase region.



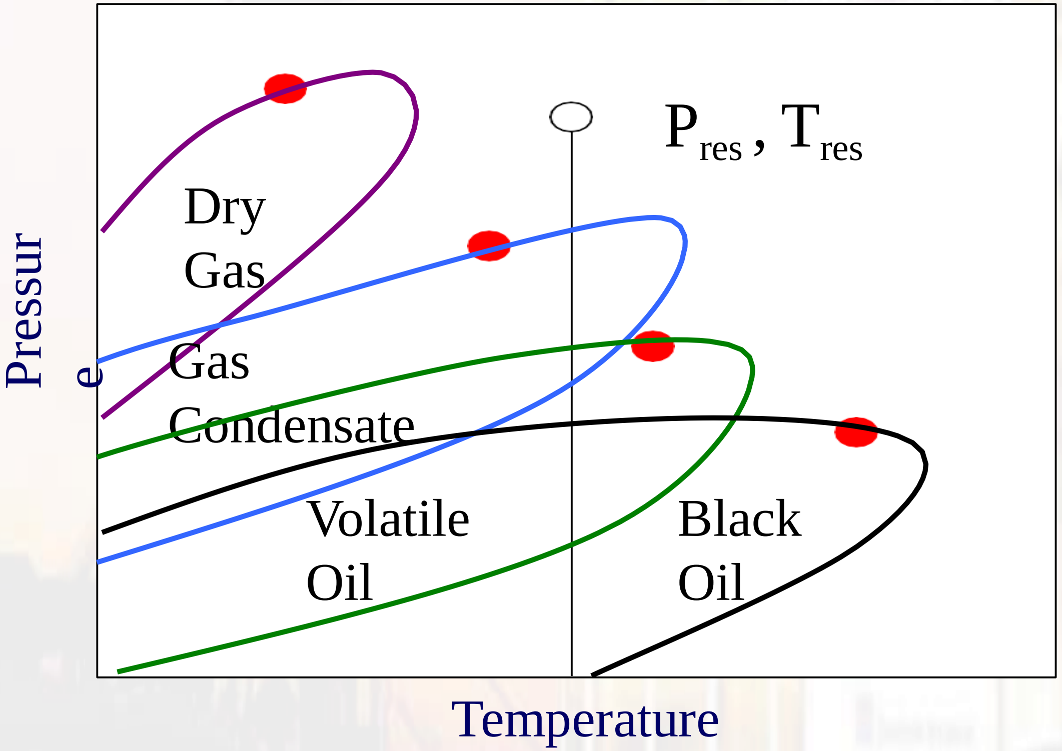

***Note:*** These multicomponent pressure-temperature diagrams are essentially used to:

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

# Classification of reservoirs fluid types

Crude oil

- Black oil
- Volatile oil
- Retrograde Condensate (gas condensate)
- Wet gas
- Dry gas



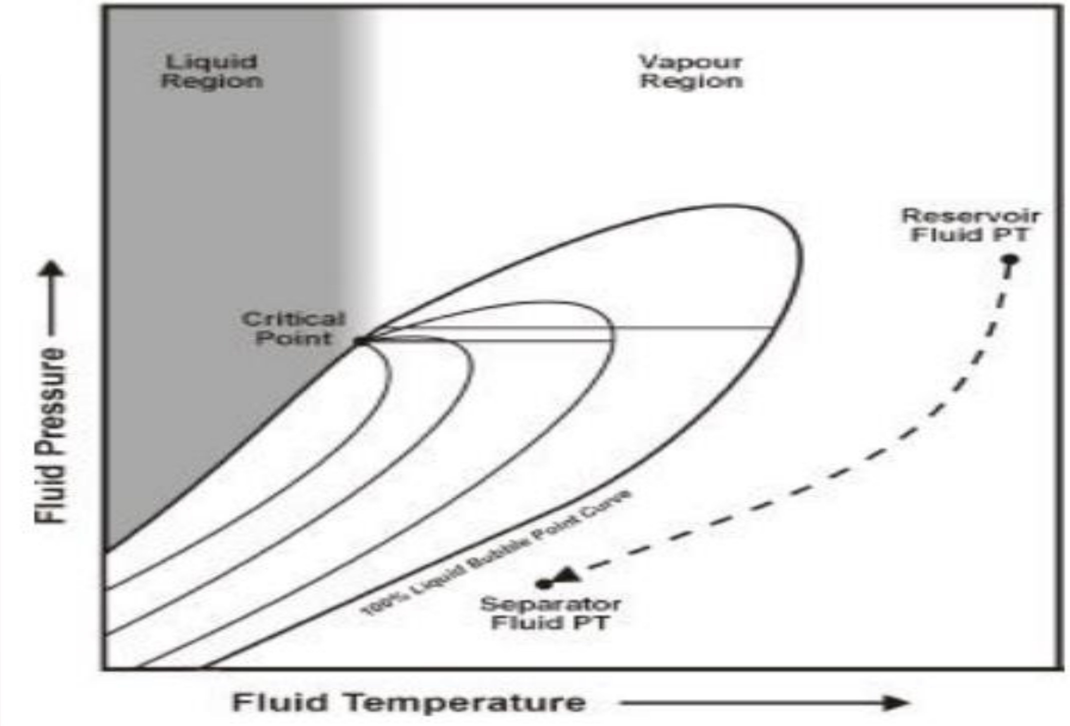

- This classification is based on the properties exhibited by the crude oil, including:
  - Physical properties, such as API gravity of the stock-tank liquid.
  - Composition.
  - Initial producing gas/oil ratio (GOR).
  - Appearance, such as color of the stock-tank liquid.
  - Pressure-temperature phase diagram.

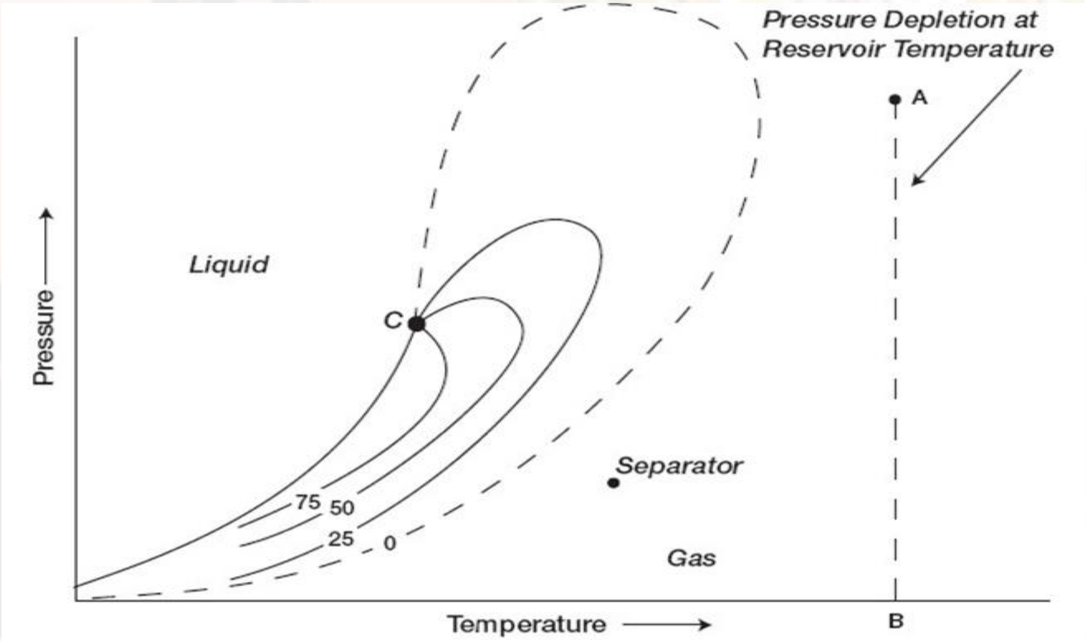
**In other meaning**: Rules of thumb will be given to identification of each of the five fluid type, which it ; ***Initial producing GOR*, *the gravity of stock tank liquid*, *and the color of stock tank liquid.***

**The classification of fluid reservoir systems is determined by:**

- **The location of the reservoir temperature with respect to the critical temperature and cricondentherm.**
- **Location of the first-stage separator pressure and temperature with respect to the phase diagram of the reservoir fluid.**

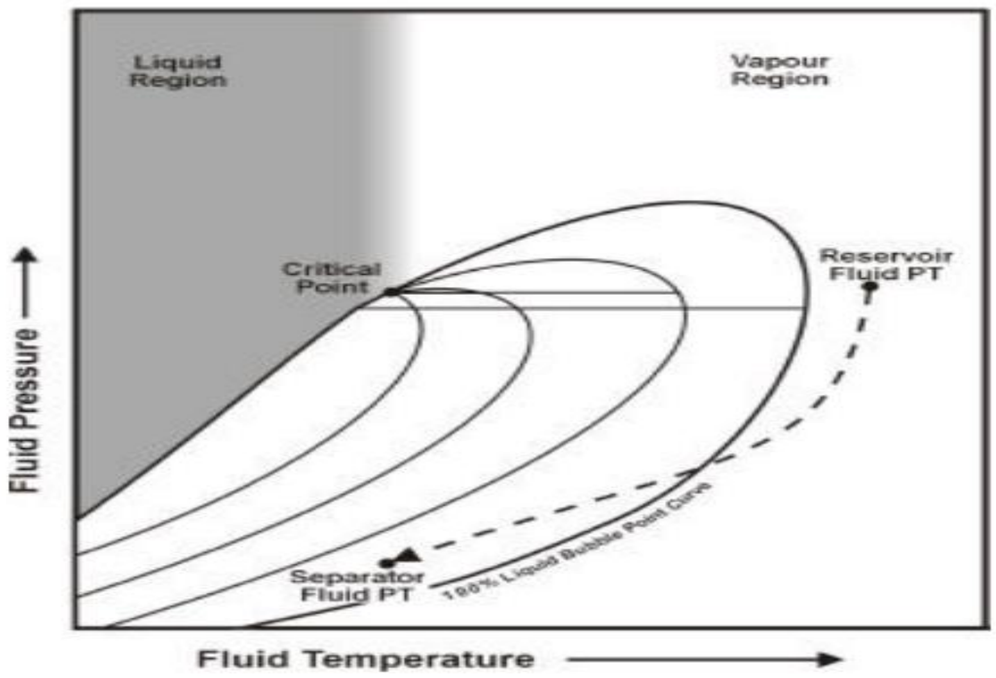
***Note:*** Each of these reservoirs can be understood in terms of its phase envelope.

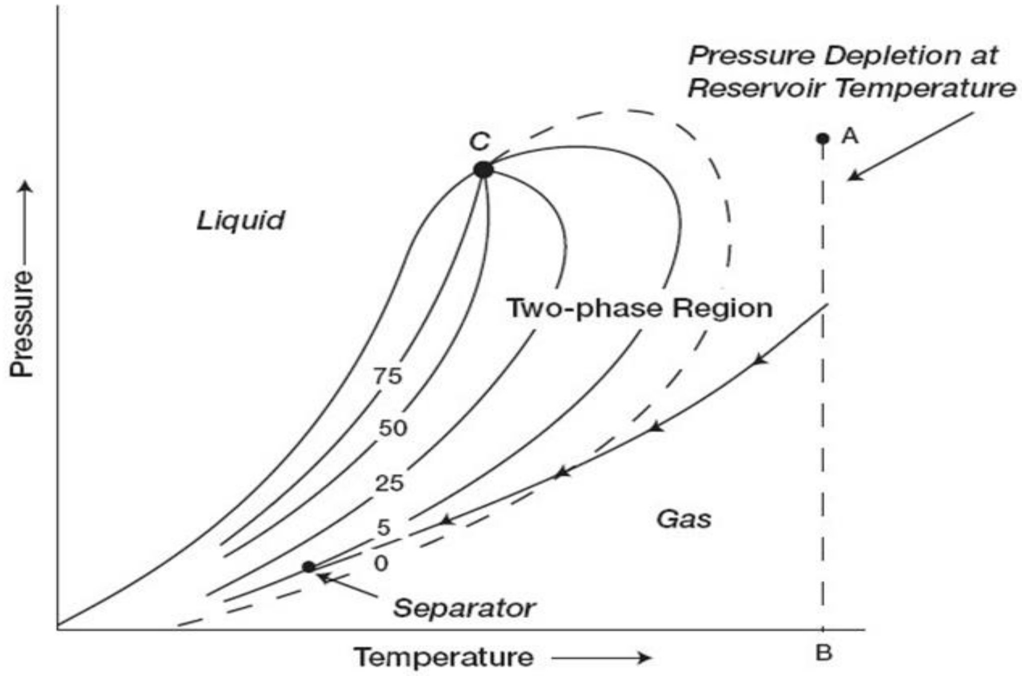



# Dry Gas

- Mainly composed of $C_1$ with some intermediates, in addition to non-HC components such as $N_2$ and $CO_2$
- The gas remains single-phase from the reservoir to surface conditions (no condensate drop-out).
- The word dry in dry gas indicates that the gas does not contain enough of the heavier molecules to form hydrocarbon liquid at the surface.
- Usually a system having a gas- oil ratio greater than 100,000 scf/STB is considered to be a dry gas.
- The only liquid associated with the gas from a dry gas reservoir is water.



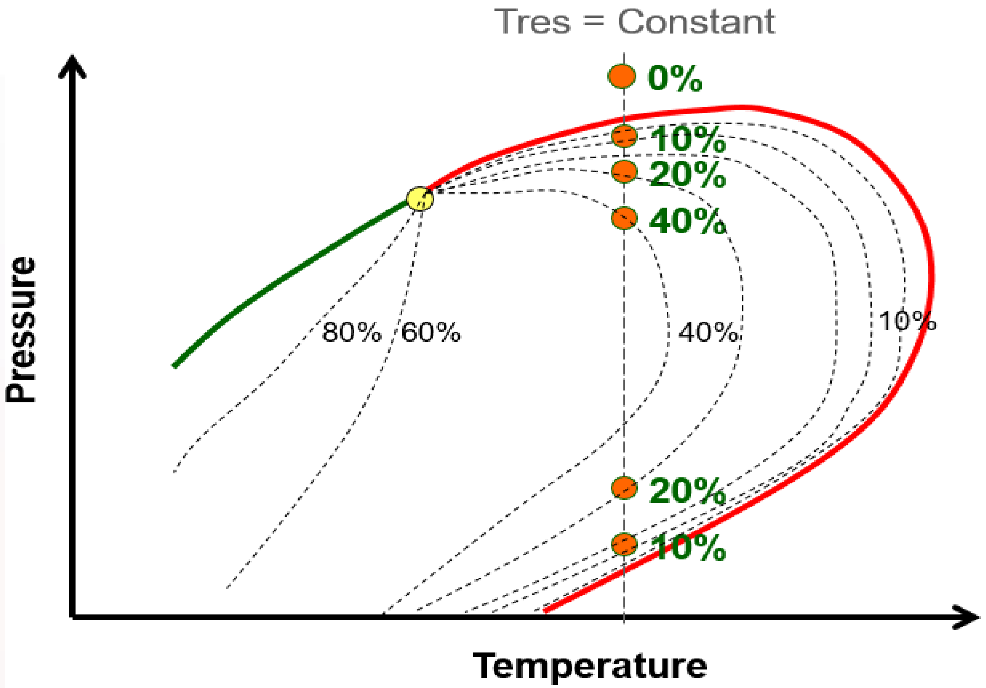



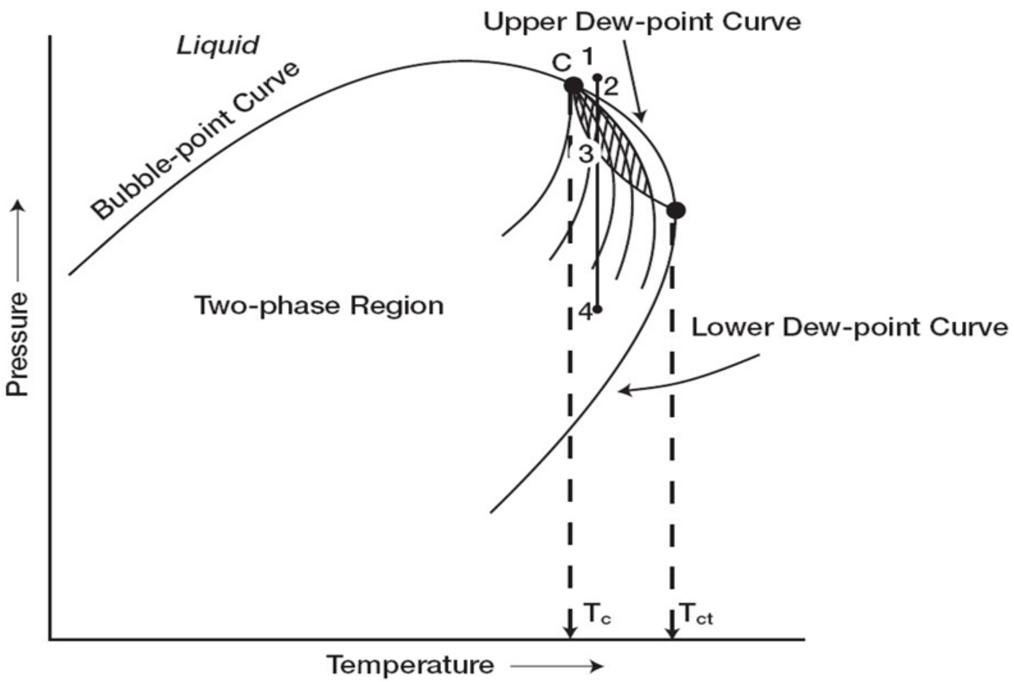

## Wet Gas

- Mainly composed of light HC components ($C_1$, $C_2$, $C_3$ and $C_4$).
- The word wet in wet gas does not mean that the gas is wet with water but refers to the HC liquid which condenses at surface condition
- Wet gas will not drop out condensate at reservoir conditions, only at surface conditions.
- Producing GOR typically higher than 50,000 Scf/Stb and will remain constant throughout depletion (i.e. during the life of reservoir)
- Note: in wet-gas reservoirs, both the producing GCRs and the stock tank condensate API gravity remain constant throughout the entire life of the reservoir.

✓ 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

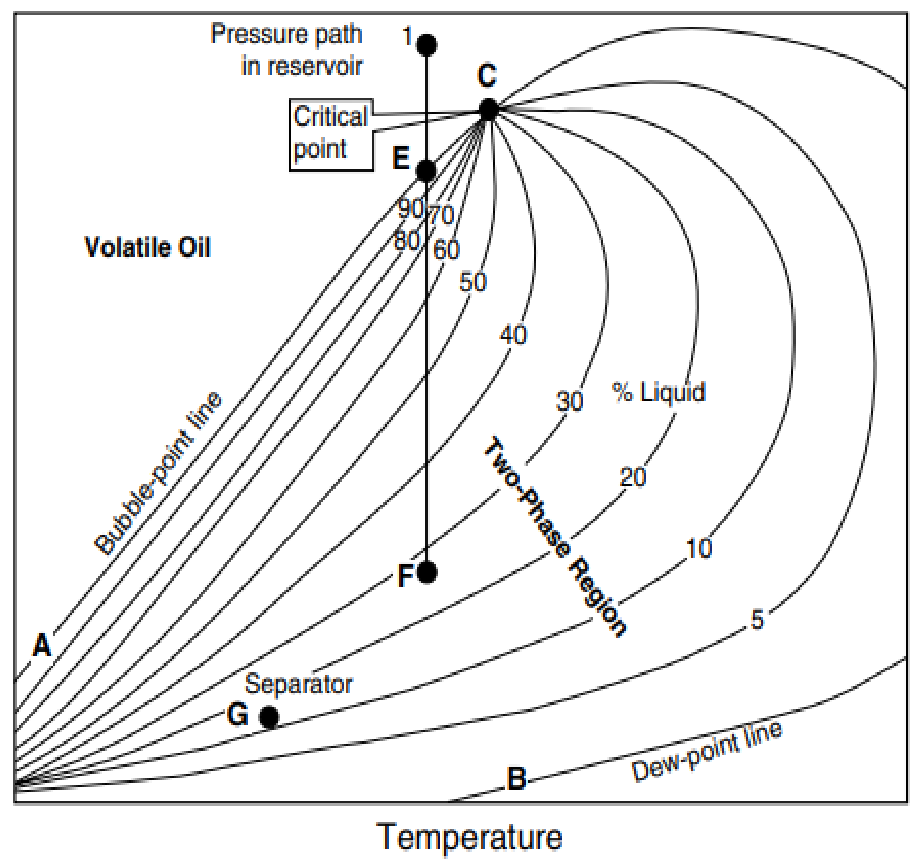


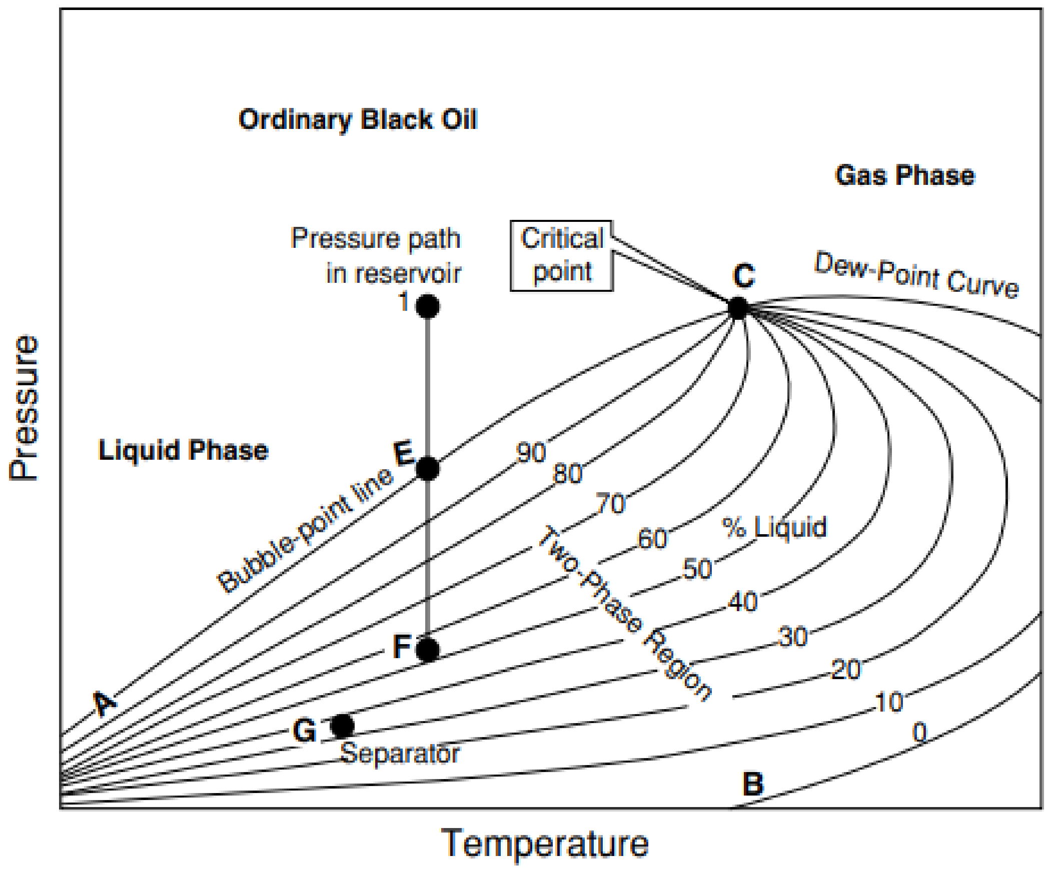

## Retrograde gases

- Retrograde gases are also called retrograde gas condensates, retrograde condensate gases, gas condensates, or condensates.
- Retrograde condensation: Formation of a liquid by isothermal decrease in pressure, (or alternatively by an isobaric increase in temperature).
- For retrograde condensation to occur the reservoir temperature must lie between the critical temperature and the cricondentherm.
- In reality the composition of the overall reservoir fluid does not remain constant. This result in a shift in the phase envelope, and leads to less revaporization at lower pressures.
- Presence of heavier components ($C_4$-$C_{7+}$) expands the phase envelope, so that the reservoir temperature lies between the critical point and cricondentherm.
- Liquid drops out during depletion due to retrograde condensation, further condensation also occurs at surface conditions.
- When the pressure is decreased on these mixtures, instead of expanding (if a gas) or vaporizing (if a liquid) as might be expected, they vaporize instead of condensing.
- Liquid dropout in the reservoir will generally lead to lower condensate recovery (immobile oil phase) and may result in poor well deliverabilities.
- Typical GOR range between 3000 to 150,000 Scf/Stb. the gas-oil ratio for a condensate system increases with time due to the liquid dropout and the loss of heavy component in the liquid.
- The stock tank liquid gravity are between 40- 60˚API and increases as reservoir pressure falls below the dew point pressure.
- The liquid can be lightly colored, brown, orange, greenish, or water – white.
- High-gravity condensates have lighter colors or are water white, while those that are low gravity have darker color

# Volatile Oil




- Typically have more heavy components than a gas condensate, which makes the fluid more *oil-like*.
- volatile oils contain relatively fewer heavy molecules and more intermediates , which characterized as those having 35+% methane through hexanes, 12.5%–20% C7+.
- volatile oils also have been called **high shrinkage crude oil**, and **near-critical oils** because the critical temperature generally lies in close proximity to the reservoir temperature.
- Large shrinkage of oil volume with pressure, due to gas vaporization as the pressure drops below the bubble-point.
- Typical GOR range between 2000 to 3300 Scf/Stb (typical range being 1750–3200 scf/STB)
- oil gravities of 40+°API (typically Oil gravities between 45° and 55° API) , and formation volume factors of 2.0 res. bbl/STB or above.
- The color of stock tank liquids is somewhat lighter in comparison to black oils and may be green, orange, or brown
- The equilibrium gas is relatively rich, and the amount of liquid produced from the reservoir gas is significant.




# Black Oil

- This type of reservoir fluid has also been called ***Low shrinkage crude oil*** or ***Ordinary oil***.
- The oil is typically composed of more than 25% $C_{7+}$.
- The oil has a relatively low shrinkage when produced.
- Typical GOR is 2000 Scf/STB or less and the GOR will be increase during production when reservoir pressure falls below the Pb.
- The formation volume factors of less than 2.0 res. bbl/STB.
- oil gravities below to 45°API
- the stock tank liquid is very dark in color indicating the presence of heavy HC, often black, sometimes with a greenish cast, or brown
- The equilibrium gas is relatively dry, and the amount of liquid produced from the reservoir gas is usually negligible (*a dry gas BO model is reasonable*).

# Classification of Petroleum Reservoir Fluids Based on Field Data and Laboratory Analysis

| Reservoir Fluid | Field Data: Initial Producing GOR (scf/STB) | Field Data: Initial API Gravity of Liquid | Field Data: Color of Stock Tank Liquid | Field Data: Mol% of $C_{7+}$ | Laboratory Analysis: Phase Change in Reservoir | Laboratory Analysis: Formation Volume Factor (res. bbl/STB) | Laboratory Analysis: Reservoir Temperature |
|---|---|---|---|---|---|---|---|
| Black oil | 250 1,750 | <45.0 | Dark | >20.0 | Bubble point | <2.0 | $<T_c$ |
| Volatile oil | 1,750–3,200 | >40.0 | Colored | 12.5–20.0 | Bubble point | >2.0 | $<T_c$ |
| Gas condensate | >3,200 | 40.0–60.0 | Lightly colored | <12.5 | Dew point | — | $>T_c$ |
| Wet gas | >50,000 | Up to 70.0 | Water white | May be present in trace amounts | No phase change | — | >Cricondentherm |
| Dry gas | — | — | — | — | No phase change | — | >Cricondentherm |