

Significance of Phase Envelop for Reservoir Fluid Characterization: A Critical Input for Identification of Gas condensate reservoir

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Abstract

PVT or Phase Behaviour Study involves the study of reservoir (oil and gas mix) fluid samples by simulating the reservoir conditions in the laboratory, under various conditions of pressures, temperatures and volumes. This reduces the uncertainty in reservoir fluid properties, provide a sound foundation for reservoir engineering studies, and improve returns on investment efficiency. The complexity of the naturally occurring hydrocarbon makes it necessary to rely on the data obtained from Phase Behaviour study in the laboratory. The physical properties of the reservoir fluid enable the reservoir analyst to evaluate the yield in terms of gas and oil volumes at surface with respect to the unit volume of reservoir fluid. These data are necessary in estimating the performance of the reservoir; Bubble point pressure, Gas Oil Ratio (GOR), Oil Formation Volume Factor (OFVF)-BO, Gas Formation Volume Factor (GFVF)-Bg, and compressibility are of primary importance in material balance calculations.

In the present work, a study of phase envelop of reservoir fluids of wells belonging to Cluster-7 field and its adjacent area located in south west of Mumbai High structure of Mumbai Offshore Basin, was carried out. The study indicated that phase envelop can be used as a commendable tool to differentiate a dry/wet well from a gas condensate well.

Keywords: Bubble point pressure, Gas oil Ratio (GOR), Oil Formation Volume Factor (OFVF), critical point, cricondentherm

INTRODUCTION

Reservoir fluids' phase behavior plays an important role in a variety of reservoir engineering, production applications, ranging from pressure maintenance to separator design to enhanced oil recovery (EOR) processes. Reservoir fluids contain many components; therefore, phase-composition data can no longer be a representative source for reservoir real composition picture. Instead, phase diagrams and ternary diagrams can give clearer picture about the kind of reservoir fluid.

Reservoir fluid behavior of a dry or wet gas in nature is not easy to be distinguished from retrograde gas condensate using the common PVT parameters like GOR, FVF, mean Isothermal compressibility.

From reservoir point of view, the different types of reservoirs can be explained by the location of the initial reservoir temperature and pressure with respect to the two-phase (gas and liquid) envelope as commonly shown on pressure-temperature (PT) phase diagrams. In **Fig. 1**, a PT phase diagram for a particular reservoir fluid of well of Western Offshore Basin, Mumbai has been shown.

The area enclosed by the bubble-point and dew-point curves represents pressure and temperature combinations for which both gas and liquid phases exist. The curves within the two-phase envelope show the percentage of the total hydrocarbon volume that is liquid for any temperature and pressure. At pressure and temperature points located above the bubble-point curve, the hydrocarbon mixture will be a liquid phase. At pressure and temperature points located above or to the right of the dew-point curve, the hydrocarbon mixture will be a gas phase. The critical point, where bubble-point, dew-point, and constant quality curves meet, represents a mathematical discontinuity, and phase behavior near this point is difficult to define. Initially, each hydrocarbon accumulation will have its own phase diagram, which depends only on the composition of the accumulation.

At temperatures greater than the cricondentherm, which is the maximum temperature for the formation of two phases, only one phase occurs at any pressure. For instance, if the hydrocarbon mixture in **Fig. 1** were to occur in a reservoir at temperature T_A and pressure p_A (point A), a decline in pressure at approximately constant temperature caused by removal of fluid from the reservoir would not cause the formation of a second phase.

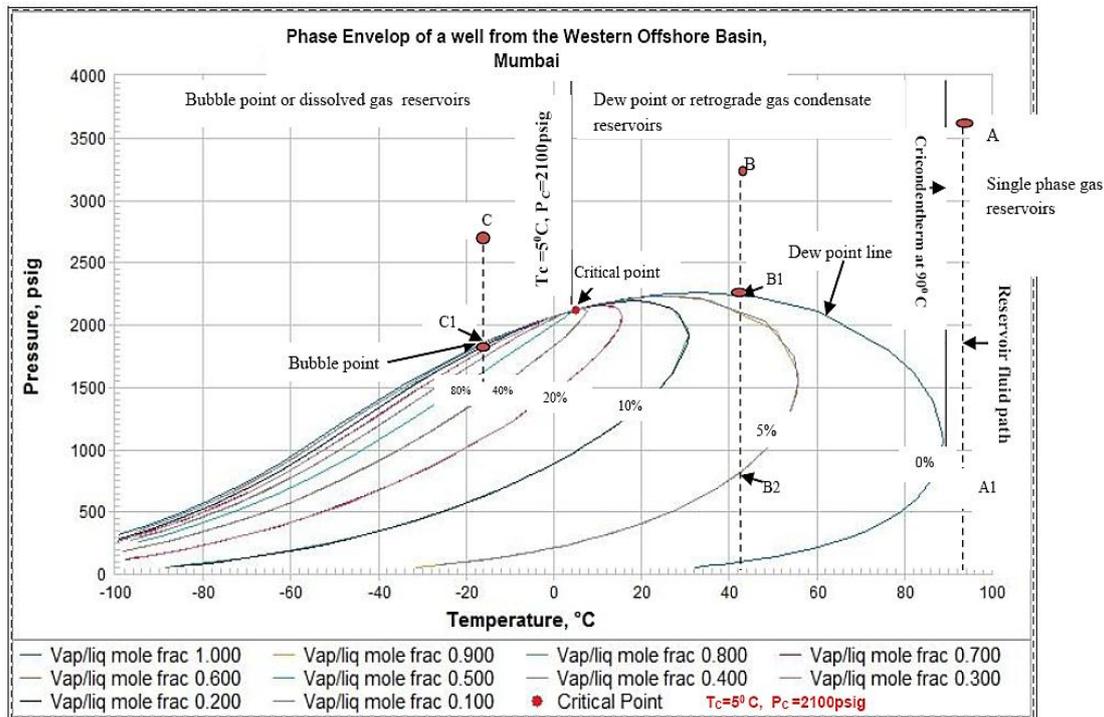


Fig 1: Phase Envelop of reservoir fluid of a well from the Western Offshore Basin, Mumbai

In **Fig 1** at point A, initially at 93°C temperature and 3600 psig pressure, since this point lies outside the two-phase region and to the right of the critical point, the fluid is originally in a one-phase gas state. Since the fluid remaining in the reservoir during production remains at 93°C , it is evident that it will remain in the single-phase or gaseous state as the pressure declines along path AA1.

While the fluid in the reservoir remains a single phase, the produced gas splits into two phases as it cools and expands to surface temperature and pressure at point A'. Thus, some condensate would be collected at the surface even though only one phase is present in the formation. The amount of condensate collected depends on the operating conditions of the separator. The lower the temperature at a given pressure, the larger the volume of condensate collected (**Fig. 1**).

In the case of a reservoir containing the same fluid as in **Fig 1**, but at a temperature of 41°C and an initial pressure of 3250 psig, point B. Here the fluid is also initially in the one-phase gas state, because the reservoir temperature surpasses the critical-point temperature. As pressure declines due to production, the composition of the produced fluid will be the same as reservoir A and will remain constant until the dew-point pressure is reached at 2250 psig, point B1. Below this pressure, a liquid condenses out of the reservoir fluid as a fog or dew. This type of reservoir is commonly called a dew-point or a gas-condensate reservoir. This condensation leaves the gas phase with a lower liquid content. The condensed liquid remains immobile at low concentrations. Thus the

gas produced at the surface will have a lower liquid content, and the producing gas-oil ratio therefore rises. This process of retrograde condensation continues until a point of maximum liquid volume is reached, 5% at 600 psig, point B2. The terminology retrograde is used because generally vaporization, rather than condensation, occurs during isothermal expansion.

Characteristic	Oils			Gases	
	Heavy oils & Tars	Black oils	Volatile Oils	Gas Condensate	Wet & Dry Gases
Initial Fluid Molecular weight	210+	70 - 210	40 - 70	23 - 40	<23
Stock Tank Oil colour	black	Brown to light green	Greenish to orange	Orange to clear	clear
St Stock Tank Oil-gravity, ^o API	5 - 15	15 - 45	42 - 55	45 - 60	45+
C ₇₊ fraction	>50	35 to 50	10 to 30	1 to 6	0 to 1
Initial dissolved GOR, scf/STB	0-200	200-900	900-3,500	3,500-30,000	30,000+
Initial dissolved GOR, v/v	0-35.6	35.6-160.2	160.2-623	623-5,340	5,340+
Initial FVF, B ₀ , RB/STB	1.0-1.1	1.1-1.5	1.5 -3.0	3.0- 20.0	20.0+
Typical reservoir temperature ^o F	90-200	100-200	150-300	150-300	150-300
Typical saturation pressure(Bubble point pressure), psia	0-500	300-5,000	3,000-7,500	1,500-9,000	---
Volatile Oil/gas ratio, STB/MMscf*	0	0-10	10-200	50-300	0-50
Maximum vol% liquid during CCE**	100	100	100	0-45	0

* At bubble point pressure

** Constant Composition Expansion of reservoir fluid

On the whole, retrograde loss will evidently be greater (a) for lower reservoir temperatures, (b) for higher abandonment pressures, and (c) for greater shift of the phase diagram to the right—the latter being a property of the hydrocarbon system. The retrograde liquid in the reservoir at any time is composed of mostly methane and ethane by volume (Table-1), and so it is much larger than the volume of stable liquid that could be obtained from it at atmospheric temperature and pressure. The composition of this retrograde liquid is changing as pressure.

Table-2: Composition (in mol %) of several reservoir fluids					
Component or Property	Dry Gas	Wet Gas	Condensate	Volatile Oil	Black Oil
CO ₂	0.10	1.41	2.37	1.82	0.02
N ₂	2.07	0.25	0.31	0.24	0.34
C ₁	86.12	92.46	73.19	57.60	34.62
C ₂	5.91	3.18	7.80	7.35	4.11
C ₃	3.58	1.01	3.55	4.21	1.01
<i>i</i> C ₄	1.72	0.28	0.71	0.74	0.76
<i>n</i> C ₄	—	0.24	1.45	2.07	0.49
<i>i</i> C ₅	0.50	0.13	0.64	0.53	0.43
<i>n</i> C ₅	—	0.08	0.68	0.95	0.21
C _{6s}	—	0.14	1.09	1.92	1.16
C ₇₊	—	0.82	8.21	22.57	56.40
γ _{API}	—	65.0	48.5	36.7	23.6
M ₇₊	—	132	184	240	274
γ ₇₊	—	0.750	0.816	0.864	0.920
CO ₂	0.10	1.41	2.37	1.82	0.02

If the initial reservoir fluid composition is found at 2700 psig and -18⁰C, point C, the reservoir would be in a one-phase state and it can be called liquid, because the temperature is below the critical-point temperature. This is called a bubble-point (or black-oil or solution-gas) reservoir. As pressure further declines during production, the bubble-point pressure will go down and in this case at 1750 psig, point C1. Below this pressure, bubbles, or a free-gas phase, will appear (**Fig 2**). When the free gas saturation is sufficiently large, gas flows to the wellbore in ever increasing quantities. Because surface facilities limit the gas production rate, the oil flow rate declines, and when the oil rate is no longer economic, much unrecovered oil remains in the reservoir.

Gas condensate reservoir:

Gas-condensate or Dew point reservoirs represent an important source of hydrocarbon reserves and have long been recognized as a reservoir type, possessing the most intricate

flow and complex thermodynamic behaviors. Gas-condensate reservoirs are characterized by producing both gas and condensate liquid at surface. Typical retrograde condensate reservoirs produce gas/liquid ratios or gas condensate ratios (GCR) of approximately 3-150 MCF/STB .

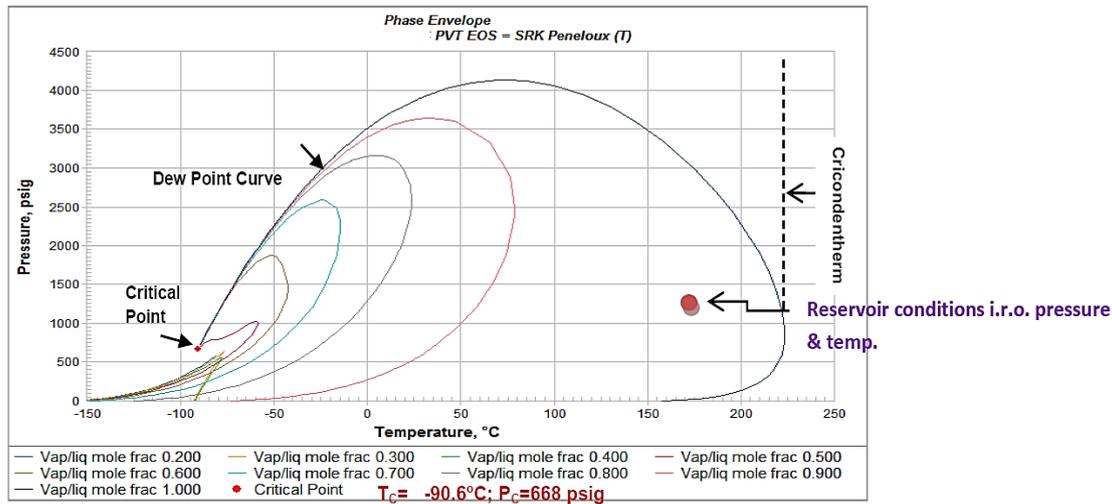


Fig 2: Phase Envelop of a gas condensate system of well of Western offshore Basir Mumbai

The phase diagram of a gas-condensate system is such that the reservoir temperatures exist between critical temperature and cricondentherm. That means the critical temperature is less than the reservoir temperature and a cricondentherm greater than the reservoir temperature (**Fig 4**). The presence of the heavy components expands the two-phase envelope of the fluid mixture to the right compared to that of wet gas. The gas-condensate reservoir is initially gas at the reservoir condition, point 1, and as the reservoir pressure decreases below the dew point, point 2, liquid condenses from gas and forms a “ring” or “bank” around the producing well in the near-well region. In normal condition, this liquid will not flow till the accumulated condensate saturation does not exceed the critical condensate saturation (S_{cc}) due to the relative permeability and capillary pressure effects in the porous medium. Once the reservoir pressure drops below the dew point, the condensate drops out in the reservoir. But at first, the condensate liquid will not flow until the accumulated condensate saturation exceeds the critical condensate saturation. This leads to a loss of valuable hydrocarbons because the condensate contains most of heavy components. This pressure-drop occurs during production which tends to form condensate banking (also known as the condensate blockage effect) around the well. This causes a loss in productivity. In laboratory PVT analysis, as the reservoir pressure further goes down to lower pressure, point 3, the liquid begins to revaporize in a PVT cell experiment. But in practical, during production, the revaporization may not take place in the reservoir because the overall composition of the reservoir fluid is changed during production. As a result of the

composition variation, the total concentration of the heavy component in the reservoir fluid will be higher than that of the original reservoir fluid. This leads to the recovery problem associated with the heavier components, which are usually not easy to recover once stuck in the reservoir. Condensate blockage near the well may cause a significant loss in well productivity for low-to-moderate permeability high-yield condensate reservoirs since the main source for pressure loss in the tight reservoir depends primarily on reservoir permeability.

Retrograde Phenomenon

Regarding multi-component mixtures (where the binary system is the simplest case), some interesting phenomena profoundly differentiate their behavior from the behavior of single-component systems. Such systems are called *retrograde phenomena*.

Although the critical point for this system is the common point between the dew and bubble point curves (the point for which liquid and vapor phases are indistinguishable), in general, this point neither represents the maximum pressure nor the maximum temperature for vapor-liquid coexistence. In fact, apposite terminology to these maxima are: cricondenbar (for the maximum pressure) and cricondentherm (for the maximum temperature).(Fig-5)

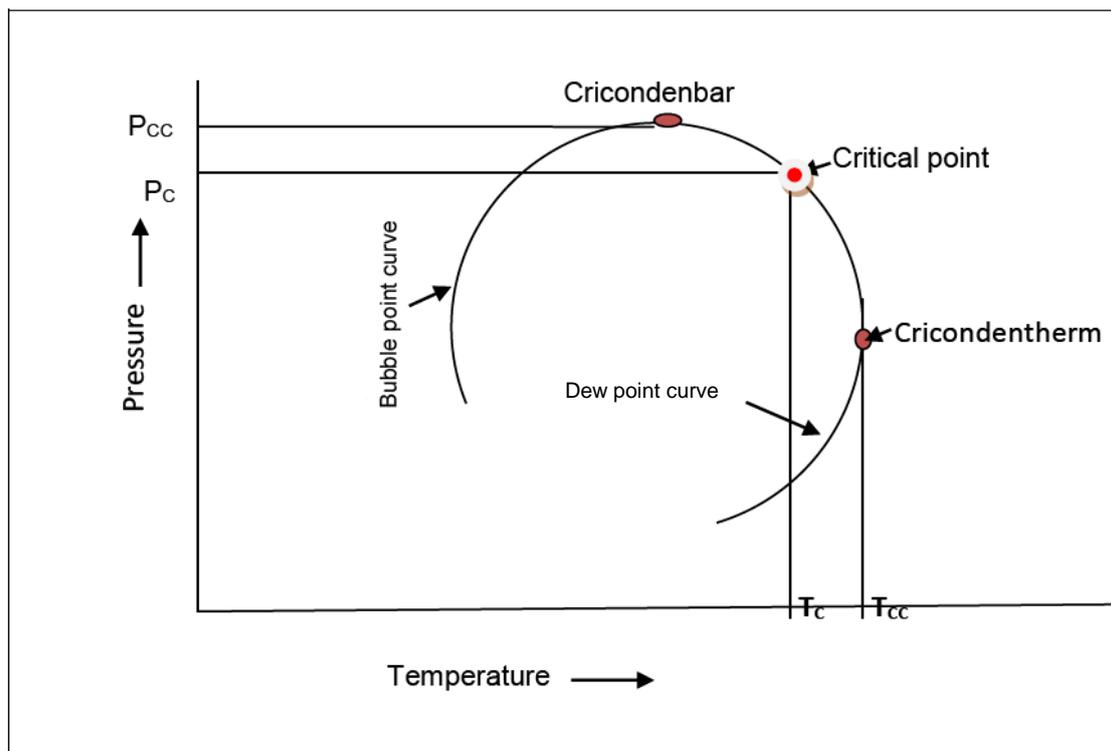


Fig 3: Cricondenbar, Cricondentherm and Critical Point

The *bubble point curve* represents the line of saturated liquid (100 % liquid with an infinitesimal amount of vapor) and the *dew point curve* represents the line of saturated vapor (100 % vapor with an infinitesimal amount of liquid).

It is common knowledge that an isothermal compression (increasing pressure while temperature remain constant) causes the condensation of a vapour. That is the *normal or expected behavior* of a vapour under compression: the more one compress it, the more liquid he may get out of it after the saturation conditions have been reached. This is always true for a *pure-component system*, such as water.

The phase diagram shown in **Fig. 1** is for the original composition only. The preferential removal of light hydrocarbon components in the vapor phase generates new hydrocarbon mixtures, which have a greater fraction of the heavier hydrocarbons. As the reservoir fluid becomes heavier, the boundary of the two-phase region in a diagram like **Fig. 1** shifts to higher temperatures.

“Larger the volume of condensate collected, higher is the fraction of heavier hydrocarbon components present in the reservoir fluid, and thus higher is the value of constants ‘a’ and ‘b’. This in turn results in higher values of critical constants T_c and P_c .”

Thus, the composition change also acts to drive the system towards higher liquid condensation. Such reservoirs are candidates for pressure maintenance by lean gas injection to limit the retrograde loss of condensate or for gas cycling to vaporize and recover some of the liquid hydrocarbons.

Bubble point reservoirs

Bubble point reservoirs are those in which the reservoir temperature is less than the critical temperature of the reservoir fluid. These reservoirs are sometimes called undersaturated because the fraction of light components present in the oil is too low for a gas phase to form at that temperature and pressure. Isothermal pressure reduction causes the appearance of a vapor phase at the bubble point pressure. Because the compressibility of the liquid phase is much lower than that of a vapor, the pressure in the reservoir declines rapidly during production in the single-phase region.

The appearance of the much more compressible vapor phase reduces the rate of pressure decline. The volume of vapor present in the reservoir grows rapidly with reduction of reservoir pressure below the bubble point. The “closeness or broadness” of the isovolume lines at the reservoir conditions can indicate the “largeness or smallness” of the portion of liquid volume vaporized during a small isothermal reduction of the pressure below the bubble-point pressure.

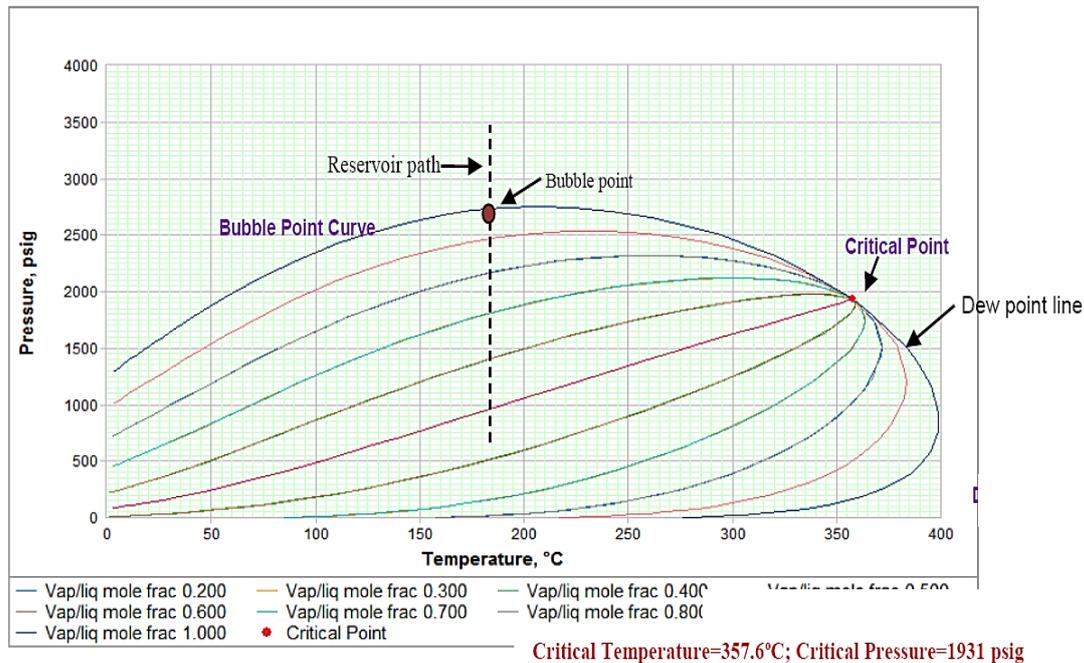


Fig.4: Phase envelop of an undersaturated oil reservoir of well from Western offshore Basin, Mumbai

Because the vapor viscosity is much lower than the liquid viscosity and the gas relative permeability goes up markedly with increasing gas saturation, the vapor phase flows more easily. Hence, the produced gas/oil ratio climbs rapidly.

SUMMARY

From the above discussion it is seen that:

- the various types of reservoirs can be defined by the location of the initial reservoir temperature and pressure with respect to the two-phase (gas and liquid) envelope as commonly shown on pressure-temperature (PT) phase diagrams
- Determining the category of reservoir fluid is essential to deduce the suitable primary recovery mechanism, like gas drive, depletion drive and water drive.
- The curves within the two-phase envelope show the percentage of the total hydrocarbon volume that is liquid for any temperature and pressure very clearly.
- At pressure and temperature points located above the bubble-point curve, the hydrocarbon mixture will be a liquid phase. At pressure and temperature points located above or to the right of the dew-point curve, the hydrocarbon mixture will be a gas phase. The critical point, where bubble-point, dew-point, and constant quality curves meet, represents a mathematical discontinuity, and phase behavior near this point is difficult to define.
- Initially, each hydrocarbon accumulation will have its own phase diagram, which depends only on the composition of the accumulation.

- The initial gas-oil ratio of production from wells completed either in the gas cap or in the oil zone of two-phase reservoirs depends on the compositions of the gas cap hydrocarbons and the oil zone hydrocarbons, as well as the reservoir temperature and pressure.
- The gas cap may contain gas condensate or dry gas, whereas the oil zone may contain black oil or volatile oil. Naturally, if a well is completed in both the gas and oil zones, the production will be a mixture of the two. Sometimes this is unavoidable, as when the gas and oil zones (columns) are only a few feet in thickness. Even when a well is completed in the oil zone only, the downward coning of gas from the overlying gas cap may occur to increase the gas-oil ratio of the production.

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