5b. Phase behavior of oil reservoirs

Black oils

Black oils consist of a wide variety of hydrocarbons, including heavy molecules. Laboratory analysis of black oils indicate 20 mole percent or higher of 'heptane+' (heptane or heavier) components. In contrast to retrograde gas systems (see below), the critical point of black oils is well up the slope of the phase envelope. The reservoir conditions are to the right of the critical point. Retrograde behavior does not occur therefore.

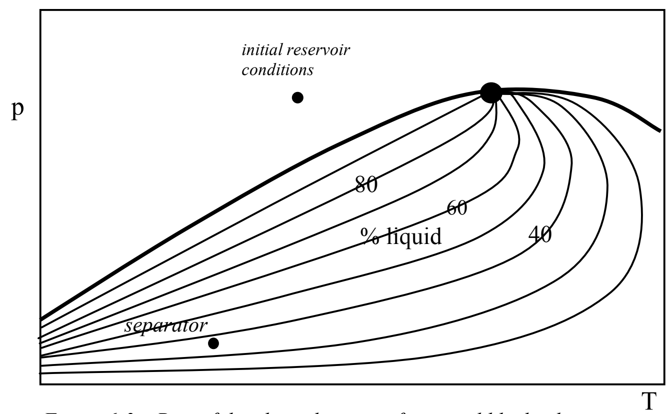

Figure 6-3 Part of the phase diagram of a typical black oil.

If the reservoir pressure is above the bubble-point pressure, the oil is undersaturated. That means that the oil could dissolve more gas if more gas were present. At its bubble point, the reservoir oil is saturated. A reduction in pressure from the bubble point will lead to a release of gas, as the two-phase region is entered. The associated gas in a black oil reservoir is usually a dry gas (see next section) except at low reservoir pressures.

The conditions at the surface separator are indicated in the diagram as well. (Note: a separator is surface equipment in which gas and liquid are separated, we'll talk about separators more in later lectures).

Additional gas evolves from the oil as it moves to the surface. Note that the separator conditions lie well within the phase envelope, which means that a reasonably large amount of liquid arrives at the surface.

Draw a possible line of isothermal reduction of reservoir pressure in the diagram

Black oils have initial gas-oil ratios of 2000 scf/STC or less. The stock tank oil generally has a gravity below 45 °API. The oil is very dark because of the heavy hydrocarbons present. The initial formation volume factor is generally 2.0 res bbl/STB. This means that the volume of oil shrinks by one-half or less on its trip to the stock tank.

You may encounter the term "dead oil" in petroleum engineering as well. Dead oils have a gas-oil ratio of 20 scf/STC or less. The surface conditions are above the bubble point pressure, so gas will not evolve from the oil during production.

Volatile oils

Volatile oils contain fewer heavy molecules than black oils and more 'intermediate' hydrocarbons (ethane through to the hexanes). The heptane+ fraction of volatile oils is between 12.5 and 20 mole percent. The lighter composition of volatile oil compared with black oil means that the temperature range covered by the phase envelope is somewhat smaller. The critical point is much lower on the envelope than for a black oil. It is close to the reservoir temperature. The isovols are not as equally spaced as in the black oil case, but concentrated nearer the bubble point line. This means that a relatively small reduction in pressure below the bubble point pressure causes the release of a large amount of gas in the reservoir. The separator conditions are indicated also.

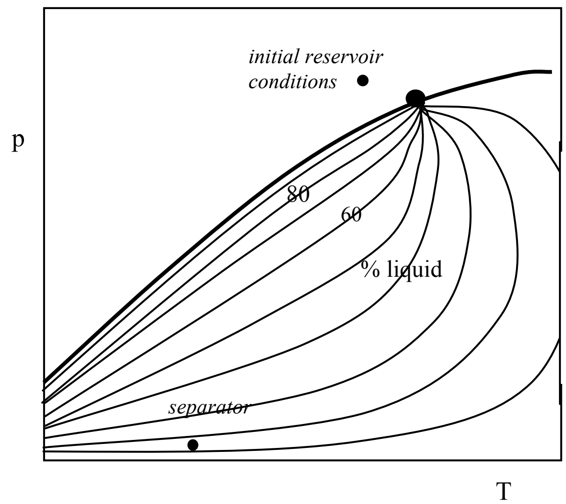

Figure 5-4 Phase diagram of a typical volatile oil

How much liquid can you expect arriving at the surface?

The gas associated with a volatile oil is usually a retrograde gas. This gas releases a lot of liquid as it moves to the surface. Often over one-half of the liquid produced in the lifetime of a volatile oil reservoir entered the wellbore as part of the gas!

Volatile oils have initial gas-oil ratios between 2000 and 3300 scf/STB. The stock oil gravity is usually 40 °API or higher. The initial formation volume factor is greater than 2.0 res bbl/STB. The oil is colored (brown/orange or sometimes green).

5.3 Gas systems

Systems that are in the gaseous state in the reservoir (referred to simply as 'gases') are divided into
1. Condensate or retrograde gases
2. Wet gases
3. Dry gases

Retrograde gas

A reservoir contains a retrograde gas (sometimes also referred to as a condensate gas) if the reservoir temperature is between the critical temperature and the cricondentherm, and the initial reservoir pressure is equal to or greater than the dew-point pressure. As fluids are produced, the reservoir pressure declines and isothermal retrograde condensation occurs in the reservoir. The heptane+ fraction is less than 12.5 mole percent in retrograde gas. (As a rule of thumb: If the mole percent of heptane+ is 12.5 or higher the reservoir fluid will be a liquid, not a gas). The separator conditions lie within the phase diagram (typically around the 5-10 % vol liquid lines)

Sketch a phase diagram for a retrograde gas. In the same diagram sketch the phase envelope for a black oil so that you can clearly see the differences. While sketching do take into account the fact that the average molecular weight in the gas is much lower than in black oil.

[picture]

Why may retrograde condensation in the reservoir lead to a drop in production?

Note that as the produced fluid is brought to the surface, it is subjected to both pressure decline and temperature decline. Thus, at the surface, liquid is accumulated in the separator as a result of normal condensation associated with a decline in temperature.

The lower limit of the initial gas-oil ratio for a retrograde gas is approximately 3300 scf/STB. The upper limit could be as high as 150,000 scf/STB. The stock tank liquid gravities are between 40 and 60 °API.

Wet gas

The phase diagram of a wet gas lies entirely below reservoir temperature. This means that a wet gas exists solely as a gas in the reservoir even when pressure drops during production. Therefore, no liquid is formed in the reservoir. The separator conditions are usually within the phase envelope, causing some liquid to be formed at the surface.

[picture]

Wet gases are generally lighter than retrograde gases. The stock tank liquid is usually water-white. True wet gases have very high gas-oil ratios. For practical purposes, a gas-oil ratio above 50,000 scf/STB indicates a wet gas.

Dry gas

In the dry gas case, the phase diagram again lies below the reservoir temperature. The conditions at the surface fall outside the phase envelope as well. This means that no hydrocarbon liquid is formed either in the reservoir or at the surface.

What composition do you think a dry gas would have?

We note that usually some liquid water is condensed at the surface (but no hydrocarbon liquids).

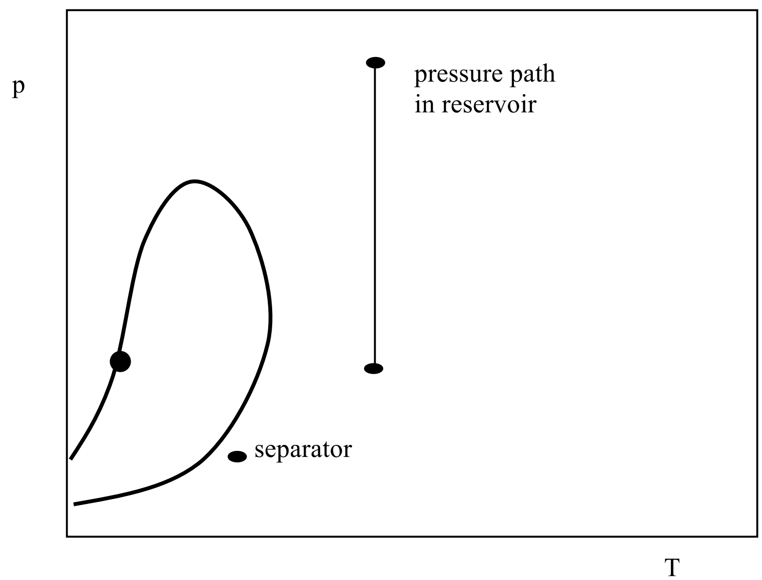

Figure 5-5 Phase diagram of a typical dry gas reservoir