5a. Phase behavior and other characteristics of petroleum reservoirs

Ultimately, an oil company is interested in the composition and the quantity of petroleum that can be produced from a reservoir. A good understanding of the phase behavior of the reservoir fluids and knowledge about the changes that the fluids undergo during production will enable the petroleum engineer to make better predictions on well productivity. In this set of lectures, we will discuss five classes of reservoirs (two oil systems and three gas systems), their phase behavior and prevailing reservoir conditions, and the consequences these have on production.

5.1 Terms and concepts related to oil production

In this lecture, it is important to realize that during production the pressure in the reservoir will drop, but the reservoir temperature will roughly stay the same. When the petroleum is transported to the surface facilities through the well bore it will undergo a further decrease in pressure and a decline in temperature. Therefore the final state and composition of the produced oil or gas will depend on the phase behavior of the fluid, and the path that the petroleum will follow in this phase diagram during production. We will investigate this for condensate gas reservoirs, wet gas systems, dry gas systems, black oil reservoirs and volatile oils. Before we do that though it is important to understand a few important petroleum engineering concepts.

Standard conditions

Standard conditions are at a temperature of 68 °F (20 °C), and atmospheric pressure. This standard pressure varies from place to place (so "standard" is not so standard after all!). In California, standard pressure is 14.70 psia. In Texas is it 14.65 psia, and in Mexico it is 15.025 psia. Note that pressure in the petroleum industry is not measured in Pascals. The unit psia stands for pounds per square inch (absolute pressure). Another unit that you will sometimes see is psig: pounds per square inch (gauge pressure).

Solution gas-oil ratio

We mentioned above that the pressure decreases as the petroleum is brought to the surface. Now suppose that we have a so-called black oil reservoir (a definition is given in section 6.2). If the pressure becomes less than the bubble pressure of the oil at any point during the decline, gas will form. How much gas is dissolved in the oil in the reservoir is measured with the solution gas-oil ratio R_s. R_s is defined as

R_s = volume of dissolved gas when brought to standard conditions /
volume of oil entering stock tank at standard conditions.

The volume of oil is measured in "stock tank barrels" or STBs. The volume of one STB is 42 gallons, or 5.615 cubic feet. The volume of gas is measured in "standard cubic feet" or scf. So the unit of Rs is scf/STB. Also used are Mscf (1000 scf) or MMscf (1 million scf) and likewise MSTB or MMSTB.
The solution gas-oil ratio is also called dissolved gas-oil ratio, and sometimes gas solubility. In the next section, a few typical values for gas-oil ratios are given.

Figure 6-1 shows the way the solution gas-oil ratio of a black oil changes as the reservoir pressure is reduced at constant temperature. The gas-oil ratio is constant for reservoir pressures above the bubble point. At these pressures, gas is not evolved in the pore space of the reservoir and all of the liquid is produced into the well bore. (Note, when the pressure is above the bubble point pressure we say that the oil is undersaturated. This indicates that it could dissolve more gas *if more gas were present*). When reservoir pressure drops below the bubble-point, the mixture enters the two-phase region in the PT diagram and gas will separate out in the reservoir. This leaves less gas in the liquid and so R_s drops.

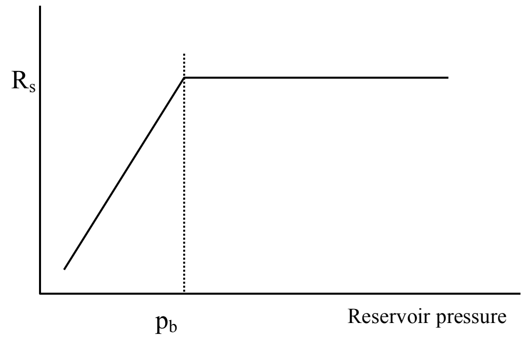

Figure 5-1 Rs of a black oil as function of temperature

Note, that the solution gas-oil ratio applies to a black oil reservoir.

Formation volume factor

How much of a reservoir oil do you need to bring to the surface to get one stock tank barrel chockablock full of oil at standard conditions? This important parameter is called the *formation volume factor of oil*. Its symbol is B_o and it is defined as

B_o = volume of oil + dissolved gas leaving reservoir at reservoir conditions /
volume of oil entering stock tank barrel at standard conditions.

If, for example, the B_o of a reservoir is 2, it means that 2 barrels of reservoir oil need to be brought to the surface to produce one STB of oil at the surface. Note that again we are interested in volumes, not in mass. This is typical in petroleum engineering. The units of the formation volume factor are res bbl/STB (reservoir barrels per STB).

The relationship of the formation volume factor of oil to reservoir pressure (at constant temperature) for a black oil is sketched in figure 5-2. As the pressure in the reservoir decreases from the initial pressure to the bubble-point pressure, the formation volume factor increases slightly.

Why would it increase slightly? Can you explain the behavior below bubble point? What would the formation volume factor be at standard pressure in this diagram?

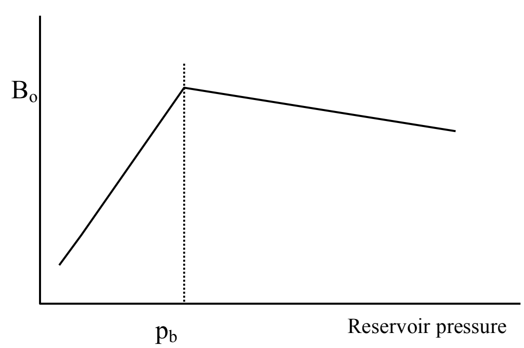

Figure 5-2 Typical formation volume factor behavior of a black oil

Also used (again for black oil) are the gas formation volume factor B_g and the total formation volume factor B_t. The gas formation volume factor is defined as

B_g = volume of gas leaving reservoir at reservoir conditions /

volume of gas at standard conditions.

Whereas the formation volume factor of oil is larger than 1, the gas formation volume factor is smaller than 1 (check this).

The total formation volume factor is defined as

B_t = volume of oil + free gas at reservoir conditions / volume of oil at standard conditions.

We can calculate the quantity of free gas using the gas-oil ratios. The gas-oil ratio at the bubble point R_{sb} gives the initial amount of dissolved gas in the oil in the reservoir (divided by the volume of oil at s.c.). The gas-oil ratio R_s at the lower reservoir pressure we are interested in gives the amount of dissolved gas left (again divided by the volume of oil at s.c.). The difference is the volume of free gas evolved during the pressure decline in the reservoir. The gas-oil ratios give the volume of gas at standard conditions however. We can convert it back to reservoir conditions by multiplying with B_g. We get:

$$B_t = B_o + B_g (R_{sb} - R_s).$$