

CHAPTER 1

RESERVOIR PRESSURE AND TEMPERATURE

3 Reservoir Pressure and Temperature

3.1 Reservoir Pressure

The initial reservoir pressure for a reservoir is one of the most important parameters that we need to obtain on a hydrocarbon accumulation. Since, once we have an estimate for the pressure, we can estimate via correlations the fluid properties, and combined with the bulk volumes, we can estimate the hydrocarbons in-place, and even a potential recovery factor. Consequently, if we don't have a reliable estimate of the reservoir pressure, we may not know what type of fluid we are dealing with; a saturated or undersaturated oil reservoir for example. In addition, we will not be able to accurately forecast production performance, since we are unsure of the initial reservoir "state." Since pressure increases with depth, we normally quote the pressure at a given depth, for example 30,600 kPa @ 3000 m. subsea (ss), or 4,500 psia @ 8000 ft ss. The figure below depicts the various reference points used to quote depth measurements.

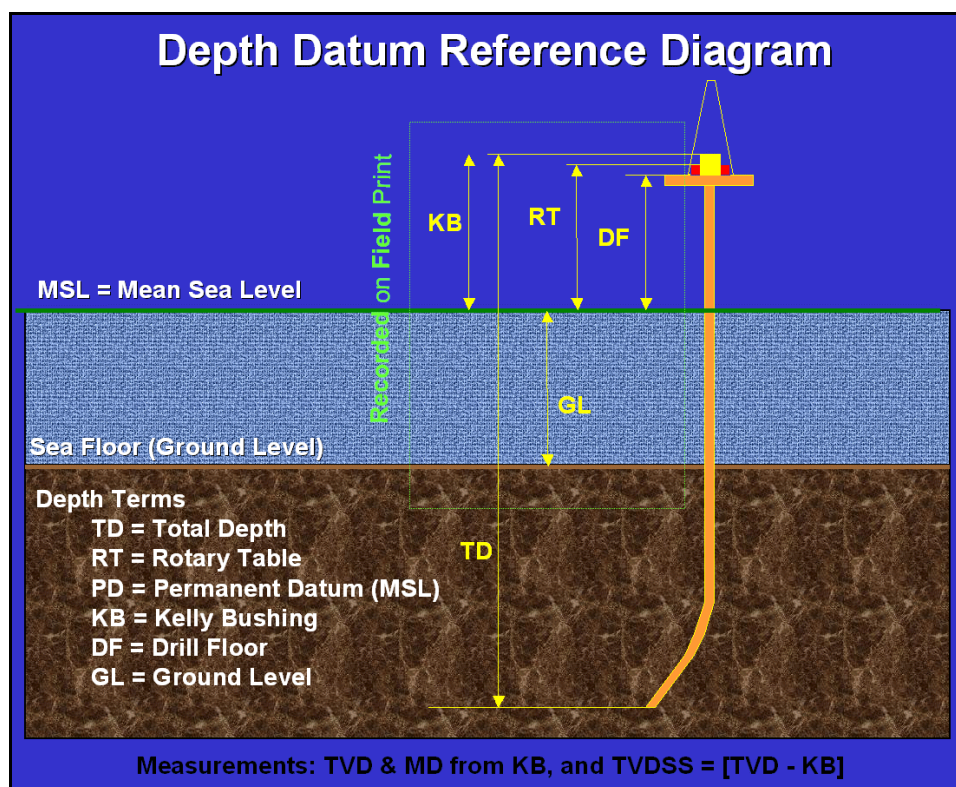


Figure 1.1 Depth Datum Reference Diagram

Note that all subsurface calculations are normally referenced to the subsea reference point, with the actual depth indicate by a minus sign and measurement type, measure depth (3000 m MD ss) or true vertical depth (-4,500 ft TVD ss). Normally one states all depth related parameters at a common depth, this is called the *datum* depth, and it is chosen to be the midpoint of the hydrocarbon column. That is, fifty percent of the hydrocarbons lie above the datum depth, and fifty percent below. The values quoted at datum are normally the values used in petroleum engineering calculations as they are the most representative numbers.

3.1.1 Pressure Gradients

In order to analyze any fluid pressure system, an understanding of fluid pressure gradients is required. While essentially only three fluids exist in the subsurface; water, oil, and gas, a broad spectrum of fluid densities can be found in each of the three phases. For example, even within a single aquifer, water salinity (and thus density) can change from fresh ($\rho_w = 62.4 \text{ lb/ft}^3$) to highly saline ($\rho_w = 68.6+ \text{ lb/ft}^3$). The density of oil, as reflected by its °API gravity, can range from being heavier than water (less than 10 °API or 62.4 lb/ft^3) to being very light (greater than 50 °API or 48.6 lb/ft^3). Gas is highly compressible and its density will be effected to a large degree by the reservoir pressure and temperature. Since it is soluble in oil, its compressibility has a profound effect upon density of oil at depth. All these factors effect the static pressure gradients of subsurface fluids. The pressure gradient of any fluid is simply the rate at which the pressure increases with depth, that is:

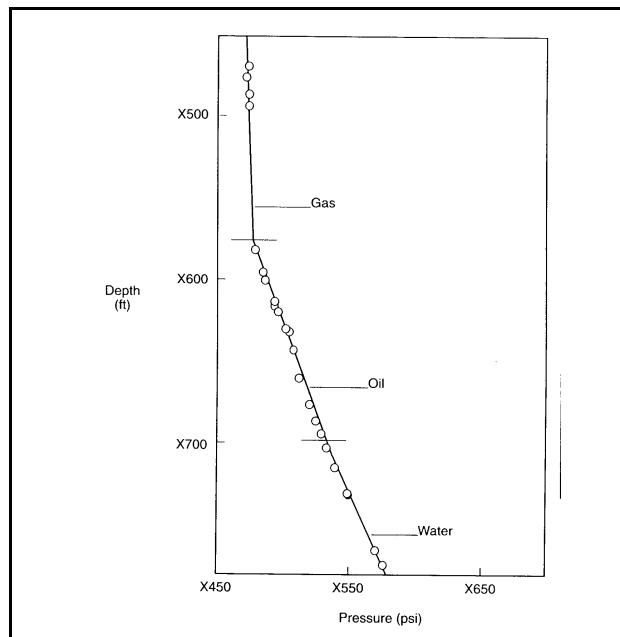


Figure 1.2 Example Pressure Gradient Plot

$$P = \left(\frac{dp}{dD} \right) \times \text{Depth} \quad (1.1)$$

Where, P = reservoir pressure (kPa or psia)
 Depth = reservoir datum depth (m or ft.)
 $\left(\frac{dp}{dD} \right)$ = fluid pressure gradient (kPa/m or psia/ft.)

Typical pressure gradients for water, oil and gas are:

$$\begin{aligned} \left(\frac{dp}{dD} \right)_{\text{water}} &= 0.45 \text{ psi / ft.} \\ \left(\frac{dp}{dD} \right)_{\text{oil}} &= 0.35 \text{ psi / ft.} \\ \left(\frac{dp}{dD} \right)_{\text{gas}} &= 0.08 \text{ psi / ft.} \end{aligned} \quad (1.3)$$

For normally pressured reservoirs, the reservoir pressure is estimated from the regional water gradient that is:

$$P_w = \left(\frac{dp}{dD} \right)_{\text{water}} \times \text{Depth} \quad (1.4)$$

Where,
 P_w = reservoir pressure (kPa or psia)
 Depth = reservoir datum depth (m or ft.)
 $\left(\frac{dp}{dD} \right)$ = water pressure gradient (kPa/m or psia/ft.)

While for over or under pressured reservoirs; reservoirs that have a pressure gradient which is greater or less than what would be estimated from the regional water gradient, the reservoir pressure relationship is of the form:

$$P_w = \left(\frac{dp}{dD} \right)_{\text{water}} \times \text{Depth} + C \quad (1.6)$$

Where,
 P = reservoir pressure (kPa or psia)
 Depth = reservoir datum depth (m or ft)
 $\left(\frac{dp}{dD} \right)$ = fluid pressure gradient (kPa/m or psia/ft)
 C = constant which is positive if the water is over pressured, or negative if under pressured.

Suppose for example we had four cased holes filled with four different fluids: column one contains gas with a specific gravity relative (γ_g) to air of 0.65 at the surface, which is converted to a gas density in lb/ft³ by:

$$\begin{aligned} \rho_{g_{sc}} &= 0.0763 \gamma_g \text{ lb/ft}^3. \\ &= 0.0763(0.65) \\ &= 0.0496 \text{ lb/ft}^3. \end{aligned} \quad (1.8)$$

Which we then convert to reservoir conditions using the gas formation volume factor (E) which is measured in scf/rcf, that is:

$$\rho_{g_{res}} = \rho_{g_{sc}} E = 0.0496(127.8) = 6.339 \text{ lbs/cuft.} \quad (1.9)$$

The resulting gas pressure gradient would then be:

$$\begin{aligned} \text{Gas Pressure Gradient} &= \frac{\rho_{g_{res}}}{144} \text{ (psia/ft)} = \frac{6.339}{144} \\ &= 0.044 \text{ (psia/ft)} \end{aligned} \quad (1.10)$$

Now if column two has oil with a stock tank density (ρ_{osc}) of 51.4 lb/ft³ (40 °API), which we again have to convert to reservoir conditions and to take into the account that has been liberated from the oil, that is

$$\rho_{ores} = \frac{(\rho_{osc} \times 5.615) + (R_s \times \rho_{gsc})}{B_o \times 5.615} \quad (1.11)$$

Where B_o is the oil formation volume factor measured in rb/stb, and R_s the solution gas-oil ratio measured in scf/stb, and if we assume that $B_o = 1.2$ rb/stb and $R_s = 350$ scf/stb, then the ρ_{ores} at reservoir conditions would be:

$$\begin{aligned} \rho_{ores} &= \frac{(\rho_{osc} \times 5.615) + (R_s \times \rho_{gsc})}{B_o \times 5.615} \\ &= \frac{(51.4 \times 5.615) + (350 \times 0.0496)}{1.2 \times 5.615} \\ &= 45.41 \text{ lbs/ft}^3 \end{aligned} \quad (1.12)$$

And hence the oil pressure gradient would be:

$$\begin{aligned} \text{Oil Pressure Gradient} &= \frac{\rho_o}{144} = \frac{45.41}{144} \text{ (psia/ft)} \\ &= 0.315 \text{ (psia/ft)} \end{aligned} \quad (1.13)$$

For column three which is filled with fresh water ($\rho_w = 62.4$ lb/ft³ at standard conditions), and assuming that B_w is equal or close to 1.0 (a reasonable assumption), then the fresh water gradient would be:

$$\begin{aligned} \text{Fresh Water Pressure Gradient} &= \frac{\rho_w}{144} = \frac{62.4}{144} \text{ (psia/ft)} \\ &= 0.433 \text{ (psia/ft)} \end{aligned} \quad (1.14)$$

And similarly for the fourth column which contains formation water with 200,000 parts per million (ppm) of total salts, which results in a density of 70.5 lb/ft³, then the pressure gradient for the saline water we obtain:

$$\begin{aligned} \text{Salt Water Pressure Gradient} &= \frac{\rho_w}{144} = \frac{70.5}{144} \text{ (psia/ft)} \\ &= 0.490 \text{ (psia/ft)} \end{aligned} \quad (1.15)$$

In many cases the units involved are different to those used in the above example, and care should be used to ensure that the correct conversion factors are employed.

Note

The density of water at standard conditions (14.7 psia and 60 °F) is 62.4 lbs/ft³ and the density of air at the same standard conditions is approximately 0.0763 lbs/ft³.

Notice also that as the density increases; the rate of change in pressure-depth increases. As density decreases, the pressure-depth plots steepen to where the gas gradient is almost vertical. Secondly, the pressure gradients in inclined beds are the same as beds in the vertical, since regardless of dip, the hydrostatic head is always the same.

Prior to drilling a well on a structure, there is still the need to estimate the hydrocarbons in-place in order to justify the expense of drilling up the structure. In many cases the reservoir pressure can be estimated from a regional water/depth gradient from other wells/structures in the area, i.e.,

$$P_w = \left(\frac{dp}{dD} \right)_{\text{water}} \times \text{Depth} \quad (1.16)$$

Where, P_w = reservoir pressure (kPa or psia)
 Depth = reservoir datum depth (m or ft.)
 $\left(\frac{dp}{dD} \right)$ = water pressure gradient (kPa/m or psia/ft.)

In the North Sea one can use 0.451 psi/ft (10.2 kPa/m) for normally pressured reservoirs. For over pressured reservoirs a gradient between 0.601 to 0.902 psi/ft (13.6 to 20.4 kPa/m) should be employed.