Lecture 3 summary:

Basic reservoir simulation concepts - rock and fluid properties

2.3. Rock Properties

Rock properties significantly influence the production of hydrocarbons.

Porosity

Porosity: the fraction of a porous medium that is void space.

If the void space in a porous medium is connected and communicates with a well bore, it is referred to as effective porosity.

Porosity values depend on rock type, as shown in Table 3.

There are two basic techniques for directly measuring porosity: core analysis in the laboratory and well logging.

Table 3. Dependence of Porosity on Rock Type

Rock Type	Porosity Range (%)	Typical Porosity (%)
Sandstone	15-35	25
Unconsolidated sandstone	20-35	30
• Intercrystalline limestone • Oolitic limestone • Dolomite	5-20 20-35 10-25	15 25 20

Porosity compressibility is a measure of the change in porosity as a function of fluid pressure *P*

$$\phi \approx \phi_0 \left[1 + c_\phi \Delta P\right] = \phi_0 \left[1 + c_\phi \left(P - P_0\right)\right], \quad \text{-------------------------- (3)}$$

Where, ϕ_0 is porosity at pressure P_0 and ϕ is porosity at pressure P .

Equation (3) is used in many reservoir flow simulators to calculate the change in porosity with respect to changes in fluid pressure.

Permeability

Permeability is a measure of the connectivity of pore spaces. It has dimensions of L^2 , where L is a unit of length.

Permeability depends on rock type. The two most common reservoir rock types are clastic reservoirs and carbonate reservoirs.

The permeability in a clastic reservoir depends on pore size. Productive sandstone reservoirs usually have permeabilities in the range of 10 md to 1000 md.

In carbonate reservoirs the typical matrix permeability tends to be relatively low. Significant permeability may be associated with secondary porosity features.

Clay material may swell on contact with fresh water, and the resulting swelling can reduce a rock's permeability by several orders of magnitude.

The vertical permeability is approximately one tenth of horizontal permeability.

Permeability can be a complex function of spatial location and orientation. Spatial and directional variations of a function are described in terms of homogeneity, heterogeneity, isotropy, and anisotropy.

When a model is being designed, the modeling team should account for the direction associated with permeability. The usual assumption is that permeability is aligned along one of three orthogonal directions.

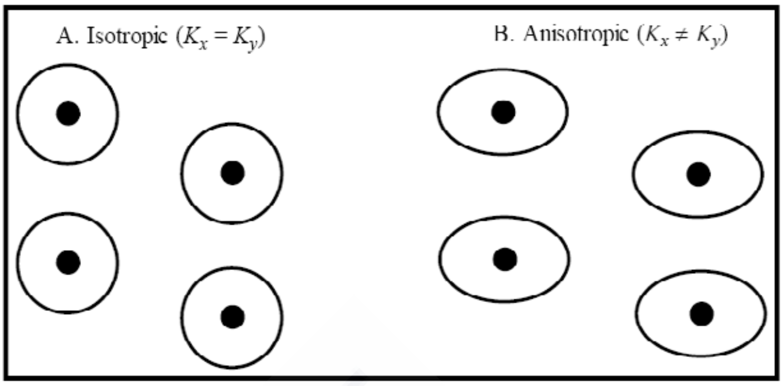

Figure 4. Effect of Permeability Anisotropy on Drainage Area

2.4. Well Log Data

Well logs provide valuable information about the formation within a few feet distance of the well bore.

Well logs are obtained by running a tool into the well bore. The tool can detect physical properties such as temperature, electrical current, radioactivity, or sonic reflections.

Table 4 illustrates the type of information that can be obtained from well log data. Porosity, saturation and formation thickness can be obtained from well logs.

Table 4. Well Log Response

Log	Variable	Response
Gamma ray	Rock type	➢ Detects shale from in situ radioactivity. ➢ High gamma ray $\Rightarrow$ shales ➢ Low gamma ray $\Rightarrow$ clean sands or carbonates
Resistivity	Fluid type	➢ Measures resistivity of formation water. ➢ High resistivity $\Rightarrow$ hydrocarbons ➢ Low resistivity $\Rightarrow$ brine

Density	Porosity	➢ Measures electron density. Electron density is related to formation density. Good for detecting gas with low density compared to rock or liquid. ➢ Small response $\Rightarrow$ low HC gas content ➢ Large response $\Rightarrow$ high HC gas content
Acoustic (sonic)	Porosity	➢ Measures speed of sound in medium. Speed of sound is faster in rock than in fluid. ➢ Long travel time $\Rightarrow$ slow speed $\Rightarrow$ large pore space ➢ Short travel time $\Rightarrow$ high speed $\Rightarrow$ small pore space
Neutron	Hydrogen content	➢ Collisions slow fast neutrons to thermal energies. Thermal neutrons are captured by nuclei, which then emit detectable gamma rays. Note: Hydrogen has a large capture cross section for thermal neutrons. Good for detecting gas. ➢ Large response $\Rightarrow$ high hydrogen content ➢ Small response $\Rightarrow$ low hydrogen content
Spontaneous potential (SP)	Permeable beds	➢ Measures electrical potential. ➢ Small response $\Rightarrow$ impermeable shales ➢ Large response $\Rightarrow$ permeable beds

2.5. Fluid Properties

The elemental composition (by mass) of petroleum is approximately (84–87)% carbon, (11–14)% hydrogen, (0.6- 8)% sulphur, (0.02-1.7)% nitrogen, (0.08-1.8)% oxygen, and (0-0.14)% metals.

The composition of petroleum shows that petroleum fluids are predominantly hydrocarbons.

The most common hydrocarbon molecules are paraffins, napthenes, and aromatics.

Paraffin is a saturated hydrocarbon, that is, it has a single bond between carbon atoms. Examples: methane and ethane. Paraffins have the general chemical formula C_nH_{2n+2}.

Napthenes are saturated hydrocarbons with a ringed structure, as in cyclopentane. They have the general chemical formula C_nH_{2n}.

Aromatics are unsaturated hydrocarbons with a ringed structure that have multiple bonds between the carbon atoms as in benzene. The unique ring structure makes aromatics relatively stable and nonreactive.

PVT diagram displays phase behavior as a function of pressure, volume, and temperature (PVT).

The types of properties of interest from a reservoir engineering perspective can be conveyed in a pressure-temperature (P-T) diagram of phase behavior like the one shown in Figure 5.

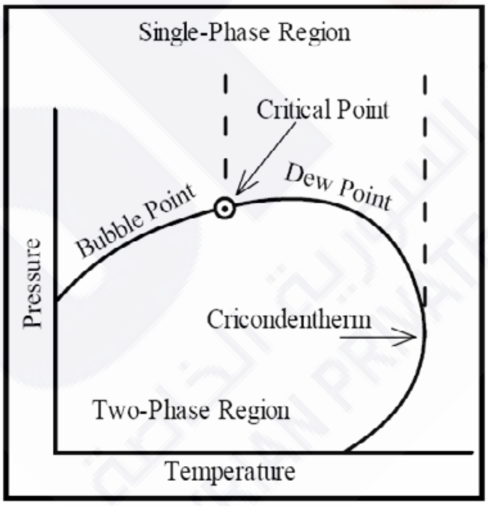

Figure 5. P-T Diagram

The P-T diagram includes both single-phase and two-phase regions. The line separating the single-phase region from the two-phase region is called the phase envelope.

The black oil region is found at low temperature and in the high pressure region above the bubble point curve separating the single-phase and two-phase regions.

If we consider pressures in the single-phase region and move to the right of the diagram by letting temperature increase towards the critical point, we encounter volatile oils.

At temperatures above the critical point but less than the cricondentherm – the maximum temperature of the phase envelope – reservoir fluids behave like condensates.

When reservoir temperature is greater than the cricondentherm, we encounter only the gas phase. Table 5 summarizes fluid types.

Table 5. Rules of Thumb for Classifying Fluid Types

Fluid Type	**Separator GOR (MSCF/STB)**	**Pressure Depletion Behavior in Reservoir**
Dry gas	No surface liquids	Remains gas
Wet gas	> 100	Remains gas
Condensate	3 & 100	Becomes gas with liquid drop out
Volatile oil	1.5 & 3	Becomes liquid with significant gas
Black oil	0.1 & 1.5	Becomes liquid with some gas
Heavy oil	~ 0	Exhibits negligible gas formation

The P-T diagram in Figure 6 compares two-phase envelopes for four types of fluids. A reservoir fluid can change from one fluid type to another depending on how the reservoir is produced. A good example is dry gas injection into a black oil reservoir. Dry gas injection increases the relative amount of low molecular weight components in the black oil. The two-phase envelope rotates counterclockwise in the P-T diagram as the relative amount of lower molecular weight components increases. Similarly, dry gas injection into a condensate can make the phase envelope transform from one fluid type to another. Thus, the way the reservoir is operated has a significant impact on fluid behavior in the reservoir and at the surface.

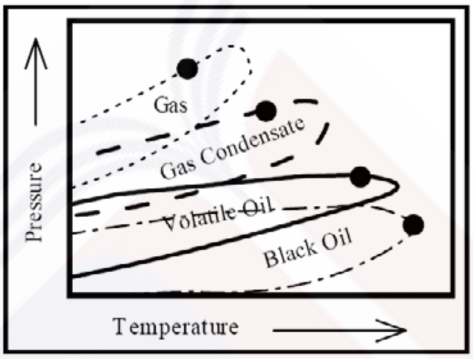

Figure 6. Typical Two-phase P-T Envelopes