Benha University
Faculty of Science
Geology Department

Post graduated Exam
Petroleum and hydrogeology Branch
Geology Department
9 Jan. 2017

Reservoir Evaluation and Petroleum Production (G605)
Time allowed: 2hrs

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Write on the following points ***each point=10 marks***

1- Preservation of organic matter.

the amount of organic matter buried in sediments is related to the ratio of organic productivity and destruction. Generally, organic matter is destroyed on the earth's surface, and only minor amounts are preserved. The deposition of an organic-rich sediment is favoured by a high rate of production of organic matter and a high preservation potential. These two factors are now discussed. Determining production and preservation for the present day is relatively easy; extrapolating back in time is harder. This problem is especially true for continental environments, whose production-destruction ratio of organic matter is largely related to the growth of land plants. Therefore, marine and continental environments should be considered separately.

2- Catagensis stage.

This phase occurs in the deeper subsurface as burial continues and temperature and pressure increase. Petroleum is released from kerogen during catagenesis-first oil and later gas. The hydrogen:carbon ratio declines, with no significant change in the oxygen:carbon ratio.

3- Liptinite organic matter.

(Type I) has a high hydrogen to carbon ratio but a low oxygen to carbon ratio. It is oil-prone, with a high yield (up to 80%). It is derived mainly from an algal source, rich in lipids, which formed in lacustrine and/or lagoonal environments.Liptinite fluoresces under UV light. Examples of liptinite-rich kerogen are found in the Devonian Orcadian shales of northeast Scotland, Type I kerogen isrelatively rare.

4- Paleothermometer.

Because of the important relationship between temperature and petroleum generation, measuring the maturity of the kerogen is important. It is not enough to be able to answer these questions: Are there organic-rich source rocks in the basin? Are they present in large enough volumes? Are they oil prone or gas prone? It is also necessary to know whether or not the source rocks have rna
tured sufficiently to generate petroleum or whether they are supermature and barren. To measure only the bottom hole temperature from boreholes does not answer the question of kerogen maturity. This measurement only indicates the

present-day temperature, which may be considerably lower than that of the past. It is necessary to have a paleothermometer, which can measure the maximum temperature to which the source rock was ever subjected. Several such tools are available, each varying in efficiency and each requiring expensive laboratory equipment and a considerable degree of technical expertise. Broadly speaking, two major groups of techniques are used for measuring the maximum paleotemperature to which a rock has been heated (Cooper, 1977):
1. Chemical paleothermometers
a. Organic
i. Carbon ratio
ii. Electron spin resonance
iii. Pyrolysis
iv. Gas chromatography
b. Inorganic
i. Clay mineral diagenesis
ii. Fluid inclusions
2. Biological paleothermometers
a. Pollen coloration
b. Vitrinite reflectance

5- Gamma Ray log uses.

- *Gamma ray log is measurement of natural radioactivity in formation verses depth.*
- *It measures the radiation emitting from naturally occurring U, Th, and K.*
- *It is also known as shale log and as shale indicator.*
- *GR log reflects shale or clay content.*
- *Clean formations have low radioactivity level.*
- *Correlation between wells,*
- *Determination of bed boundaries, and sand count.*
- *Evaluation of shale content within a formation,*
- *Mineral analysis,*
- *Particularly useful for defining shale beds when the sp is featureless.*
- *GR log can be run in both open and cased hole*

6- Definition and classification of porosity.

Definition and Classification

Porosity is the first of the two essential attributes of a reservoir. The pore spaces, or voids, within a rock are generally filled with connate water, but contain oil or gas within a field. Porosity is either expressed as the void ratio, which is the ratio of voids to solid rock, or, more frequently, as a percentage:

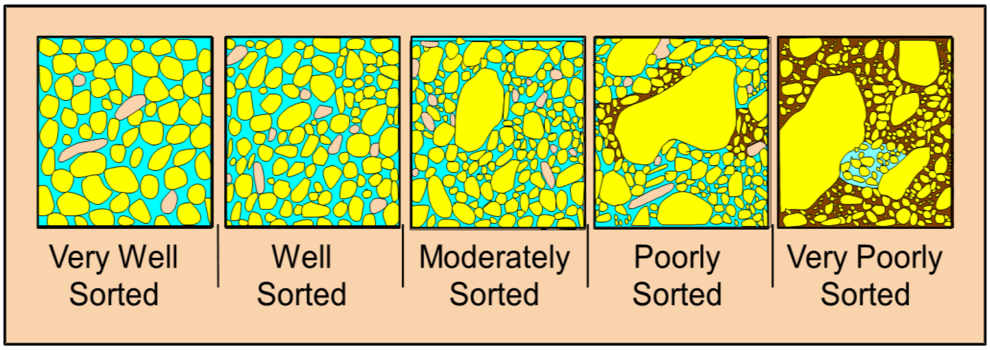
$$\text{Porosity (\%)} = \frac{\text{volume of voids}}{\text{total volume of rock}} \times 100 .$$

Porosity is conventionally symbolized by the Greek lowercase letter phi (Φ). Pores are of three morphological types: catenary, cul-de-sac, and closed
Catenary pores are those that communicate with others by more than one throat passage. Cul-de-sac, or dead-end, pores have only one throat passage‘connecting with another pore. Closed pores have no communication with other pores.
Catenary and cul-de-sac pores constitute effective porosity, in that hydrocarbons can emerge from them. In catenary pores hydrocarbons, can be flushed out by a natural or artificial water drive. Cul-de-sac pores arc unaffected by flushing, but may yield some oil or gas by expansion as reservoir pressure drops. Closed pores

are unable to yield hydrocarbons (such oil or gas having invaded an open pore subsequently closed by compaction or cementation). The ratio of total to effective porosity is extremely important, being directly related to the permeability of a rock.

7- Relationship between porosity, permeability, and grain sorting.

Porosity increases with improved sorting. As sorting decreases, the pores between the larger, framework-forming grains are infilled by the smaller particles. Permeability decreases with sorting for the same reason (Fraser, 1935; Rogers and Head, 1961; Beard and Weyl, 1973). As mentioned earlier, sorting sometimes varies with the grain size of a particular reservoir sand, thus indicating a possible correlation between porosity and grain size.



8- Factors controlling porosity gradient.

Studies of Recent sands, such as those of Pryor (1973), show that they have porosities of some 40 to 50% and permeabilities of tens of darcies. Most sandstone reservoirs, however, have porosities in the range of 10 to 20% and permeabilities measurable in millidarcies. Although fluctuations do occur, the porosity and permeability of reservoirs decrease with depth. This relationship is of no consequence to the production geologist or reservoir engineer concerned with developing a field, but it is important for the explorationist who has to decide the greatest depth at which commercially viable reservoirs may occur.

The porosity of a sandstone at a given depth can be determined if the porosity gradient and primary porosity are known (Selley, 1978):

where

$\Phi D = \Phi p - GD$,

ΦD *porosity at a given depth*

Φp *primary porosity at the surface*

G porosity gradient(% Φ */km)*

D burial depth

1- *Texture also affects the gradient: Poorly sorted sands with abundant clay matrix compact more and lose porosity faster than do clean, well-sorted sands*
2- *Also, affect the porosity gradient of sand, Because the rate of a chemical reaction increases with temperature, the higher the geothermal gradient, the faster the rate of porosity loss.*
3- *Pressure gradient also affects porosity. Abnormal pressure preserves porosity, presumably by decreasing the effect of compaction (Atwater and Miller, 1965).*

With best wishes

Dr. Mohamed Moustafa Afife

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