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مخبر الموارد المعدنية و الطاقوية
Laboratory of Mineral and Energy Resources

Course of:

Principal Notions on Petroleum Geology

Designed for Undergraduate students (License 3)

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Objectives:

After completing this course, students should be able to:

- Define Geology and how it applies to the petroleum industry.
- Name the three rock types.
- List the components of the rock cycle.
- Explain the three basic principles of relative age dating.
- Define and explain a rock formation.
- Explain the origin of hydrocarbons.
- Define porosity.
- List the controls on porosity.
- Define permeability.
- Define a reservoir.
- List the two most common reservoir rock types and give some general characteristics of each type.
- Explain fluid distribution in a petroleum reservoir.
- Explain the three different types of migration.
- List and describe the basic hydrocarbon traps.
- Appraisal from fluid movement in reservoir rocks

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General Introduction:

Geology is the science that deals with the history and structure of the earth and its forms, especially as recorded in the rock record. A basic understanding of its concepts and processes is essential in the petroleum industry, for it is used to predict where oil accumulations might occur. It is the job of the petroleum geologist to use his/her knowledge to reconstruct the geologic history of an area to determine whether the formations are likely to contain petroleum reservoirs. It is also the job of the geologist to determine whether the recovery and production of these hydrocarbons will be commercially profitable.

The physical characteristics of a reservoir, how petroleum originated and in what type of rock, what types of fluids exist in the reservoir, how hydrocarbons become trapped, and basic well log analysis are some of the concepts vital to the production and recovery efforts of any exploration or energy service company.

CHAPTER I:

GENERALITIES

1 Earth an Evolving Planet

About 4.6 billion years ago, Earth began to evolve from a conglomeration of chunks of matter into a differentiated planet with continents, oceans and an atmosphere. The primitive planet grew and began to heat up due to the collision of in-falling material striking other accreted material at high velocities. There were three general processes that contributed to the heating of the planet: collision, compression by the weight of the accreted material, and radioactive decay**(Figure 1)**.

It is likely that accretion and compression raised the internal temperature of the planet to an average of about 1000°C. Radioactive elements also had a profound effect on the evolution of Earth. The decay of these elements contributed to a rise in interior temperature to approximately 2000°C, the temperature at which iron will melt.

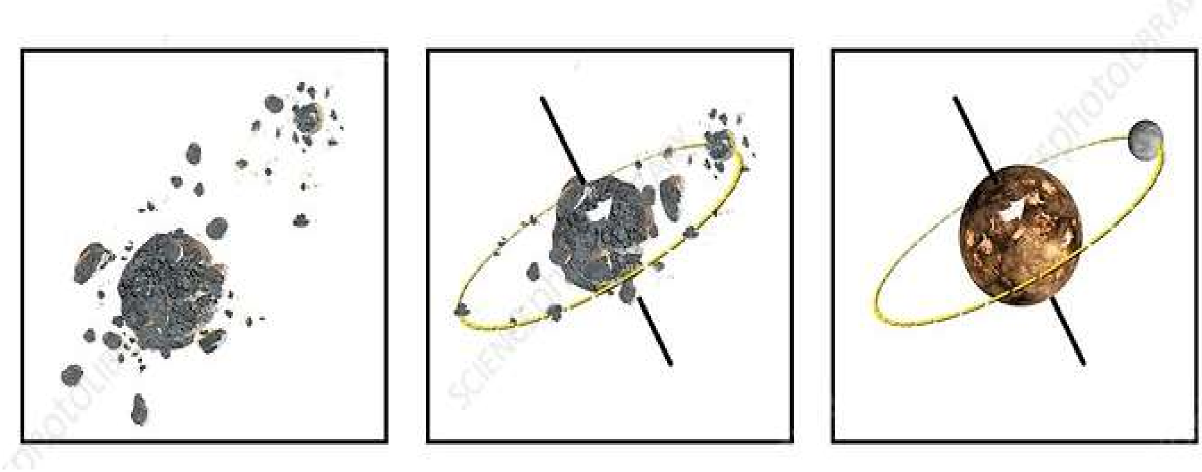

Figure 1. Collision of material onto primitive Earth (science photo library)

This is important because the melting of iron, which makes up about one- third of the planet, initiated the process by which Earth became the planet we know today. Iron is denser than most other elements on Earth. When it melted, the iron sank and formed the planet's core. The other molten materials were lighter and therefore separated and floated upward, creating a layered body. The very lightest materials floated to the top, cooled, and formed Earth's crust. This differentiation also initiated the escape of lighter gases, which eventually led to the formation of the atmosphere and oceans.

2 Geology Basics

The earth is composed of three basic layers: the core, the mantle, and the crust. The crust is the layer that is of most importance in petroleum geology. Geologists distinguish between oceanic crust and continental crust. Oceanic crust lies under the oceans and is thin about 5-7 miles (8-11km) and is made up primarily of heavy rock that is formed when molten rock (magma) cools**(Figure 2)**. Continental crust is thick about 10-30 miles (16-48 km) and is composed of rock that is relatively light as compared to oceanic crust. The crust is continuously changing and moving because of two major forces of nature orogeny and weathering/erosion.

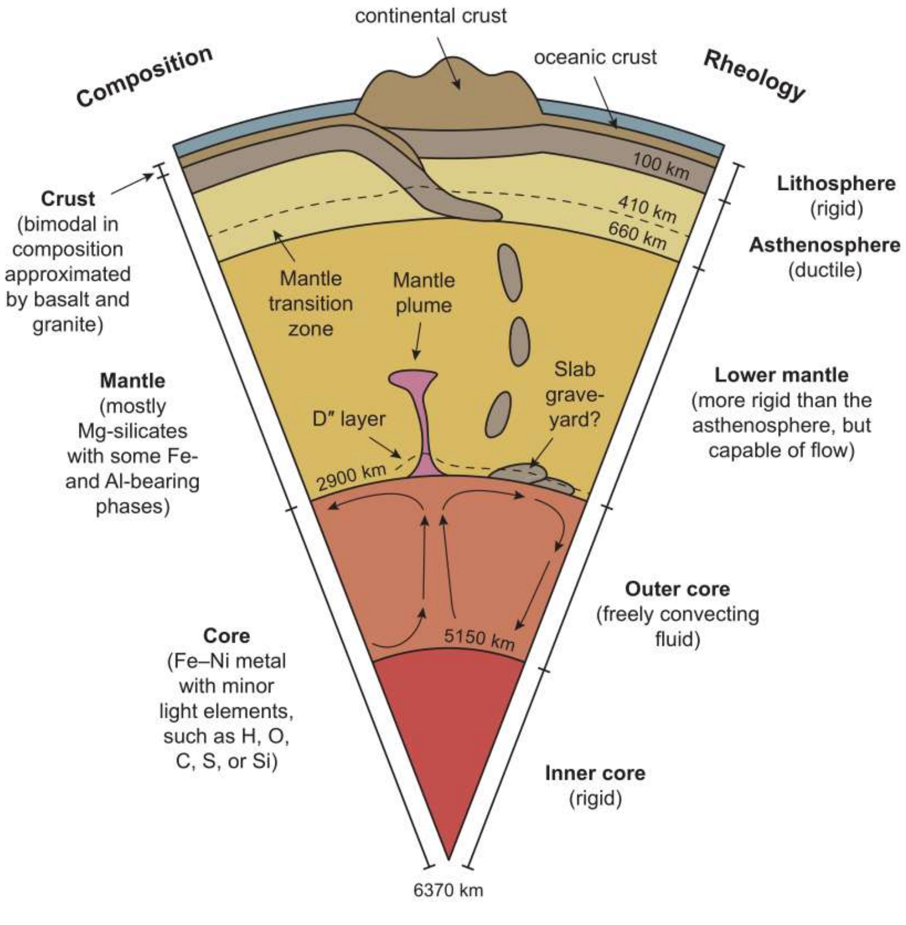

Figure 2. Schematic cross section through the present-day Earth outlining differences in composition (left) and rheology (right) between layers. Not to scale. (Science photo library)

Orogeny, or mountain building, is a process in which the layers of the crust are folded and pushed upward by such processes as plate tectonics and volcanism. Weathering and erosion are the opposing forces in which the sediments are broken down and transported.

There are two types of weathering**(Figure 3)**:

2.1 *Physical:*occurs when solid rock is fragmented by physical processes that do not change the rock's chemical composition. These processes include wind (aeolian forces), water (freezing, flowing, wave action, etc), heat, and even glacial movement. Frost wedging is one example of physical weathering.

2.2 *Chemical:* occurs when minerals in a rock are chemically altered or dissolved. The weathering of potassium feldspar to form kaolinite, clay, is an example of chemical weathering.

Weathering and erosion are closely interrelated geological processes. As a rock weathers, it becomes susceptible to erosion. Erosion is the removal of weathered debris. These and additional forces and processes have resulted in the creation of subsurface geological formations in which petroleum reservoirs are found.

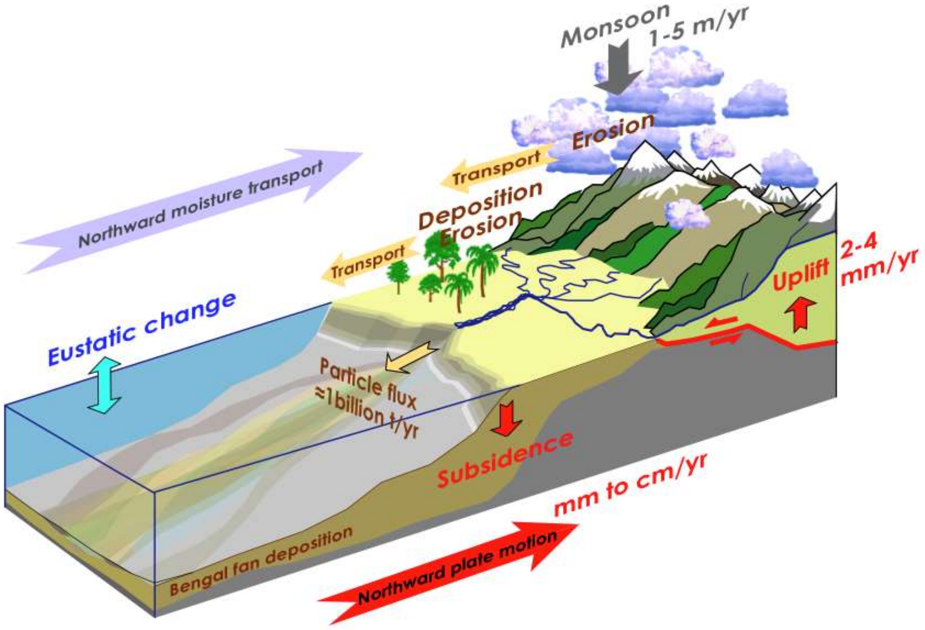

Figure 3. Weathering and erosion (science photo library)

3 Basic Rock Types

The earth's crust is composed of three basic rock types**(Figure 4)**:

3.1 *Igneous rocks:*are formed from the crystallization of molten rock (magma or lava) from within the earth's mantle. Common igneous rocks include granite, basalt, and gabbro.

3.2 *Metamorphic rocks:*are formed from pre-existing rocks by mineralogical, chemical and/or structural changes in response to marked changes in temperature, pressure, shearing stress, and chemical environment. These changes generally take place deep within the earth's crust. Examples of common metamorphic rocks include slate, marble and schist.

3.3 *Sedimentary rocks:*are formed as sediments, either from eroded fragments of older rocks or chemical precipitates. Sediments lithify by both compactions, as the grains are squeezed together into a denser mass than the original, and by cementation, as minerals precipitate around the grains after deposition and bind the particles together. Sediments are compacted and cemented after burial under additional layers of sediment. Thus, sandstone forms by the lithification of sand particles and limestone by the lithification of shells and other particles of calcium carbonate. These types of rocks are typically deposited in horizontal layers, or strata, at the bottom of rivers, oceans, and deltas. Limestone, sandstone, and clay are typical sedimentary rocks.

Igneous, metamorphic, and sedimentary rocks are related by the rock cycle, the circular process by which each is formed from the others. Rocks are weathered to form sediment, which is then buried.

During deeper and deeper burial, the rocks undergo metamorphism and/or melting. Later, they are deformed and uplifted into mountain chains, only to be weathered again and recycled.

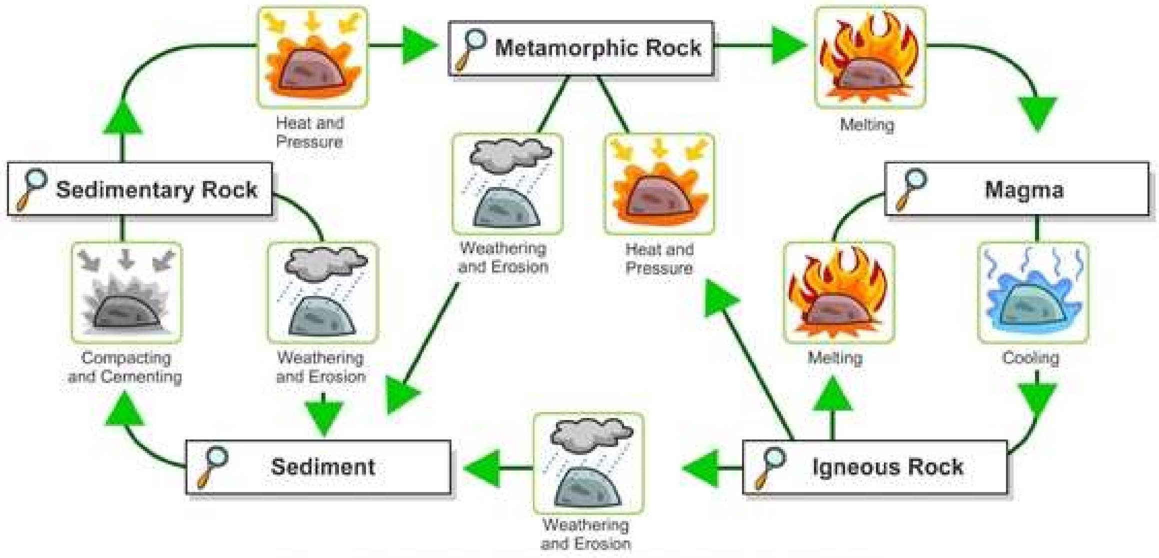

Figure 4. Rock cycle (http://rockcycle.wikispaces.com/rock+cycle)

4 Basic Classification and Types of Sedimentary Rocks

The two main groups of sedimentary rocks are classified on the basis of their origin.

4.1 *Clastic Sedimentary:*Rocks-formed as a result of the weathering or fragmentation of pre-existing rocks and minerals and classified on the basis of their textures, primarily the sizes of the grains. Sedimentary rocks are dividedinto coarse-grained: conglomerates, medium-grained: sandstones, and fine-grained: siltstones, mudstones, and shales. Within each textural category, clastics are further subdivided by mineralogy, which reflects the parent rock, for example, quartz-rich sandstone or feldspar-rich sandstone.

4.2 *Chemical or Biochemical Sedimentary*:Rocks-formed as a result of chemical processes. Primary carbonate deposition results from the precipitation and deposits Formed by plants and animals that utilize carbonates in their life processes. The most abundant mineral chemically or biochemically precipitated in the oceans is calcite, most of it the shelly remains of organisms and the main constituent of limestone. Many limestones also contain dolomite, a calcium-magnesium carbonate precipitated during lithification. Gypsum and halite are formed by the chemical precipitation during the evaporation of seawater.

5 Sedimentary rocks producing Hydrocarbons

There are five types of sedimentary rocks that are important in the production of hydrocarbons**(Figure 5)**:

Figure 5. Sedimentary rock types (https://geologydegree.org/rocks/sedimentary/)

5.1 *Sandstones:*Sandstones are clastic sedimentary rocks composed of mainly sand size particles or grains set in a matrix of silt or clay and more or less firmly united by a cementing material (commonly silica, iron oxide, or calcium carbonate). The sand particles usually consist of quartz, and the term “sandstone”, when used without qualification, indicates a rock containing about 85-90% quartz.

5.2 *Carbonates:* broken into two categories, limestones and dolomites. Carbonates are sediments formed by a mineral compound characterized by a fundamental anionic structure of CO3-2. Calcite and aragonite CaCO3 are examples of carbonates.Limestones are sedimentary rocks consisting chiefly of the mineral calcite (calcium carbonate, CaCO3), with or without magnesium carbonate. Limestones are the most important and widely distributed of the carbonate rocks.Dolomite is a common rock forming mineral with the formula CaMg(CO3)2. A sedimentary rock will be named dolomite if that rock is composed of more than 90% mineral dolomite and less than 10%mineral calcite.

5.3 *Shales:*Shale is a type of detrital sedimentary rock formed by the consolidation of fine-grained material including clay, mud, and silt and has a layered or stratified structure parallel to bedding. Shales are typically porous and contain hydrocarbons but generally exhibit no permeability. Therefore, they typically do not form reservoirs but do make excellent cap rocks. If shale is fractured, it would have the potential to be a reservoir.

5.4 *Evaporates:*Evaporates do not form reservoirs like limestone and sandstone, but are very important to petroleum exploration because they make excellent cap rocks and generate traps. The term “evaporite” is used for all deposits, such as salt deposits, that are composed of minerals that precipitated from saline solutions concentrated by evaporation. On evaporation the general sequence of precipitation is: calcite, gypsum or anhydrite, halite, and finally bittern salts. Evaporites makeexcellent cap rocks because they are impermeable and, unlike lithified shales, they deform plastically, not by fracturing. The formation of salt structures can produce several different types of traps. One type is created by the folding and faulting associated with the lateral and upward movement of salt through overlying sediments. Salt over-hangs create another type of trapping mechanism.

6 Geologic Time and Age Dating,

Geologic time and Earth's geologic history are concepts that need to be clearly understood and how they relate to the petroleum industry. It takes millions of years and specific conditions for organic and sedimentary materials to be converted to recoverable hydrocarbons.

The late eighteenth century is generally regarded as the beginning of modern geology. During this time, James Hutton, a Scottish physician and gentleman farmer, published his Theory of the earth with Proof and Illustrations (1785) which put forth the principle of uniformity. This principle states that the geologic processes and forces now operating to modify the earth's crust have acted in much the same manner and with essentially the same intensity throughout geologic time, and that past geologic events can be explained by forces observable today. This is known as the classic concept "the present is the key to the past"**(Figure 6)**.

Before radioactive materials were discovered, geologists used this and other principles and an understanding of fossils to determine the relative ages of sedimentary rock layers; that is, how old they are in relation to one another. Relative dating does not tell us how long ago something took place, only that it followed one event and preceded another. Once radioactivity was discovered, geologists used the physics of radioactive decay to pinpoint a rock's absolute age, that is, how many years ago it formed. Absolute dating did not replace relative dating, but simply supplemented the relative dating technique. The principle methods that have been used for direct radio-chronology of sedimentary rocks are as follows:

1. The Carbon-14 technique for organic materials.
2. The Potassium-Argon and Rubidium-Strontium techniques for glauconites, hornblende, microclines, muscovites, biotites, etc.
3. The Thorium-230 technique for deep ocean sediments and aragonite corals.
4. The Protactinium-231 technique for ocean sediments and aragonite corals.
5. The Uranium-238 technique for apatite, volcanic glass, zircon, etc.

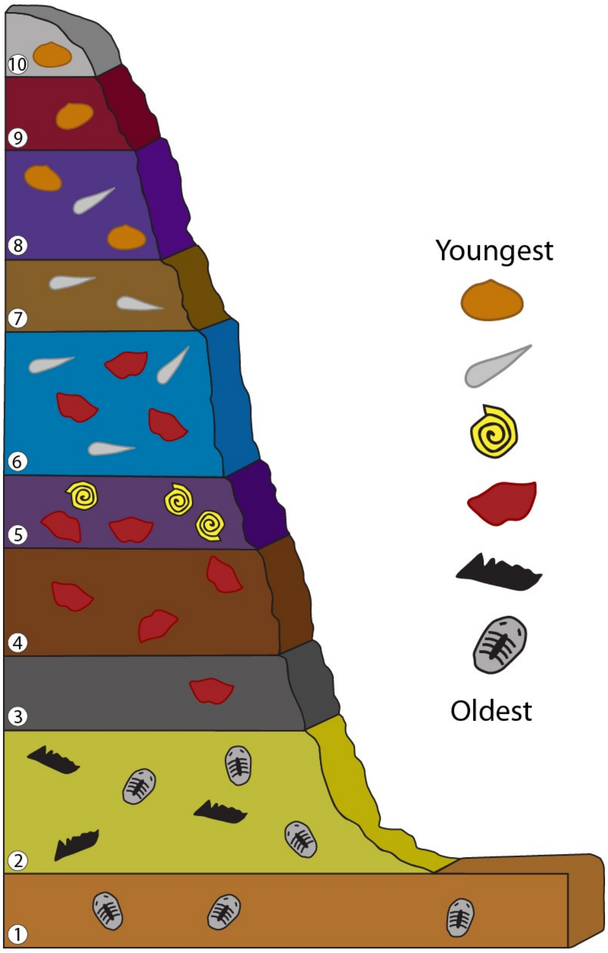

Figure 6. Relative age dating with fossils is very common and we can use this data to make interpretations about the environment(https://www.sciencephoto.com/)

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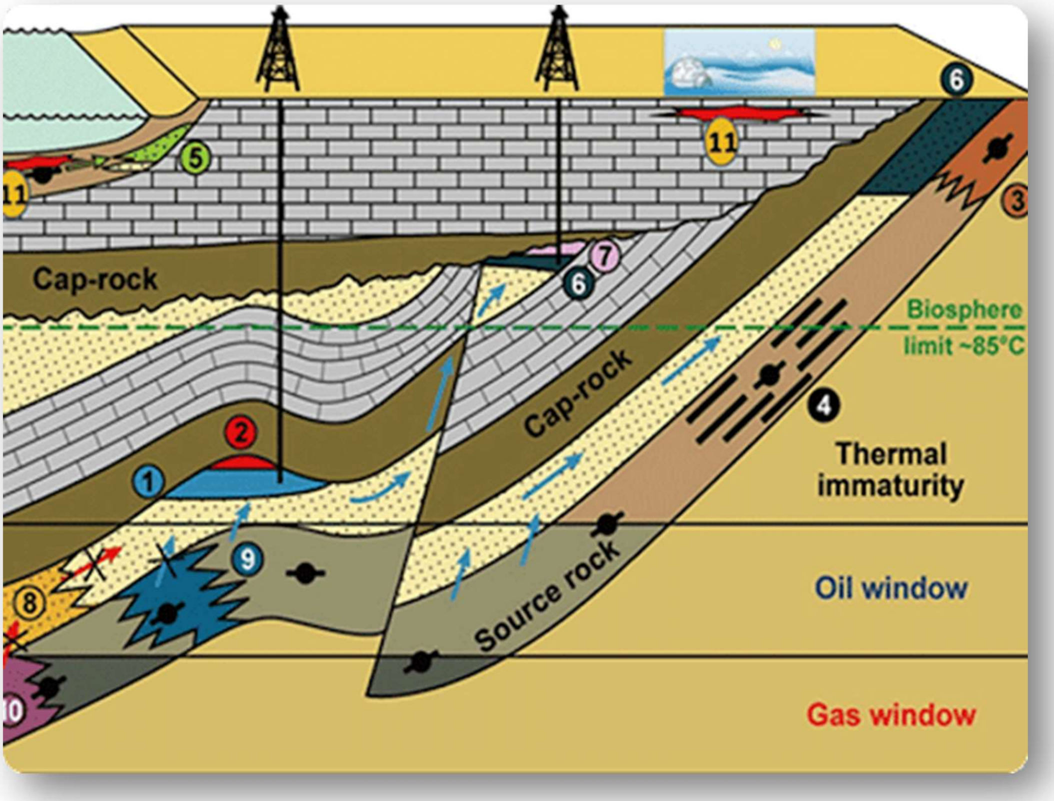
During the nineteenth and twentieth century's, geologists built on the knowledge of their predecessors and started to build a worldwide rock column. Although it will never be continuous from the beginning of time, the above principles have allowed geologists to compile a composite worldwide relative time scale**(Table 1)**.

Era	System & Period	Series & Epoch	Some Distinctive Features	Years Before Present
CENOZOIC	Quaternary	Recent	Modern man.	11,000
		Pleistocene	Early man; northern glaciation.	1/2 to 2 million
	Tertiary	Pliocene	Large carnivores.	13 ± 1 million
		Miocene	First abundant grazing mammals.	25 ± 1 million
		Oligocene	Large running mammals.	36 ± 2 million
		Eocene	Many modern types of mammals.	58 ± 2 million
		Paleocene	First placental mammals.	63 ± 2 million
MESOZOIC	Cretaceous		First flowering plants; climax of dinosaurs and ammonites, followed by Cretaceous-Tertiary extinction.	135 ± 5 million
	Jurassic		First birds, first mammals dinosaurs and ammonites abundant.	181 ± 5 million
	Triassic		First dinosaurs. Abundant cycads and conifers.	230 ± 10 million
PALEOZOIC	Permian		Extinction of most kinds of marine animals, including trilobites. Southern glaciation.	280 ± 10 million
	Carboniferous	Pennsylvanian	Great coal forests, conifers. First reptiles.	310 ± 10 million
		Mississippian	Sharks and amphibians abundant. Large and numerous scale trees and seed ferns.	345 ± 10 million
	Devonian		First amphibians; ammonites; fishes abundant.	405 ± 10 million
	Silurian		First terrestrial plants and animals.	425 ± 10 million
	Ordovician		First fishes; invertebrates dominant.	500 ± 10 million
	Cambrian		First abundant record of marine life; trilobites dominant.	600 ± 50 million
	Precambrian		Fossils extremely rare, consisting of primitive aquatic plants. Evidence of glaciation. Oldest dated algae, over 2,600 million years; oldest dated meteorites 4,500 million years.	

Table 1. Geological time scale (NPS Geologic Resources Inventory, 2020)

CHAPTER II:

SOURCE ROCK & HYDROCARBON GENERATION



1 Introduction:

A source rock is a rock that can generate natural gas and/or crude oil. Gas and oil form from ancient organic matter preserved in sedimentary rocks. As sediments are deposited, both inorganic mineral grains, such as sands and mud, and organic matter (dead plants and animals) are mixed. Most organic matter is lost on the surface by decay, a process of oxidation. The decaying organic matter on land gets oxygen from the air, and the decaying organic matter on the ocean bottom gets the oxygen from out of the water. Some organic matter, however, is preserved. It was either rapidly buried by other sediments before it decayed or was deposited on the bottom of a sea with stagnant, oxygen-free waters. The black color in sedimentary rocks comes primarily from its organic content. Black-colored, organic-rich sedimentary rocks include coal, shale, and some limestones. When woody plant material is buried, it is transformed into coal and methane gas (CH4) by temperature and time. This is why coal mines are dangerous; they contain methane gas and sometimes explode. Coal deposits are drilled to produce coal seam or coal bed gas, which is pure methane gas.

Shale is the most common sedimentary rock, and many are black. Black shale commonly has 1 to 3% organic matter by weight and can have up to 20%. Green or gray shale has only about 0.5% organic matter. Black shales contain a large variety of organic matter that includes single-celled plants and animals that live floating in the ocean, algae, spores, pollen and bacteria. They have the right chemical composition to generate both natural gas and crude oil. In some areas, such as North Africa and the Middle East, organic-rich dark limestones are also source rocks. The first factor to be assessed in an exploration play in an area yet to be drilled is whether a source rock is present. If so, then we ask, “How good is it? Will it generate oil or gas? Has it generated hydrocarbons already?” To answer these questions, we must know the basics of what constitutes a source rock, how to classify source rocks, and how to estimate potential**(Figure 7)**.

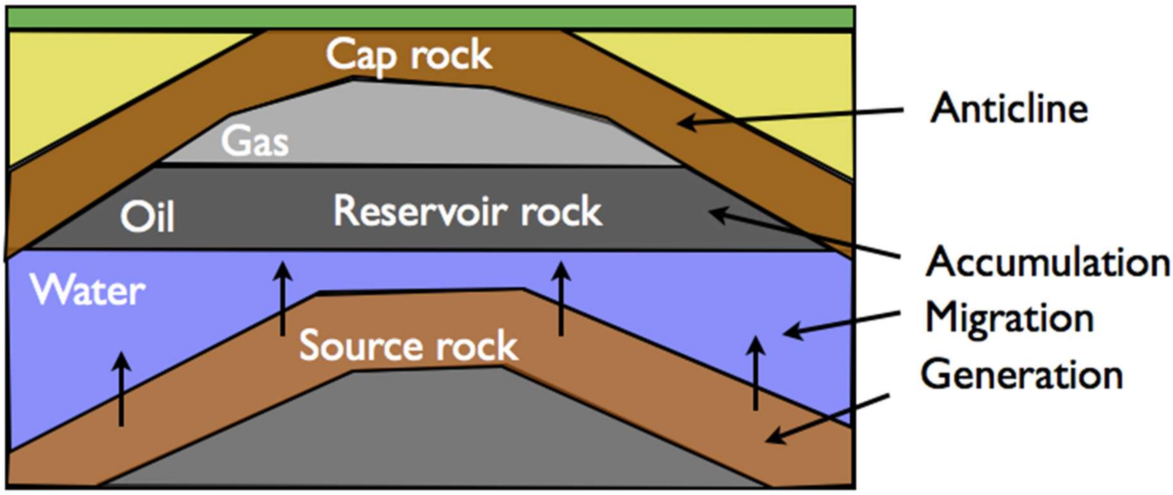


Figure7. Oil generation, migration, and accumulation (Pennwell Books, 2001)

2 Definitions of source rock types

Source rocks can be divided into at least four major categories:

2.1 *Potential:* Rock which contains organic matter in sufficient quantity to generate and expel hydrocarbons if subjected to increased thermal maturation.

2.2 *Effective:* Rock which contains organic matter and is presently generating and/or expelling hydrocarbons to form commercial accumulations.

2.3 *Relic effective:* An effective source rock which has ceased generating and expelling hydrocarbons due to a thermal cooling event such as uplift or erosion before exhausting its organic matter supply.

2.4 *Spent:* An active source rock which has exhausted its ability to generate and expel hydrocarbons either through lack of sufficient organic matter or due to reaching an overmature state.

3 Characterizing source rocks

To be a source rock, a rock must have three features:

- Quantity of organic matter
- Quality capable of yielding moveable hydrocarbons
- Thermal maturity

The first two components are products of the depositional setting. The third is a function of the structural and tectonic history of the province**(Figure 8)**.

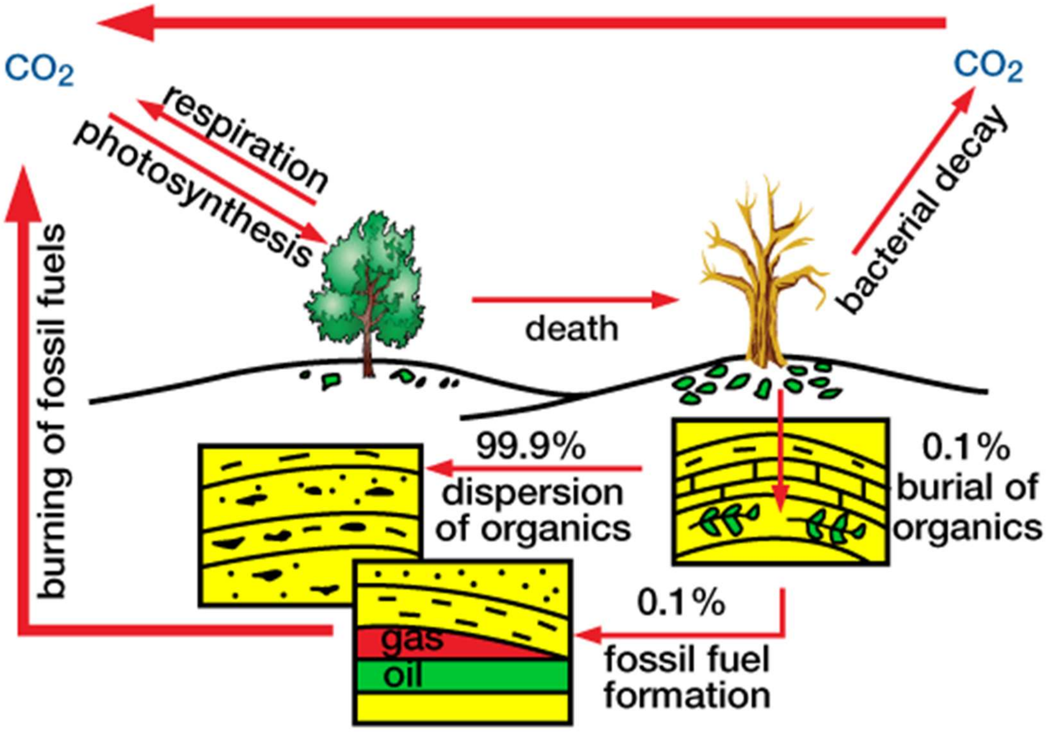


Figure8. Carbon cycle(Pennwell Books, 2001)

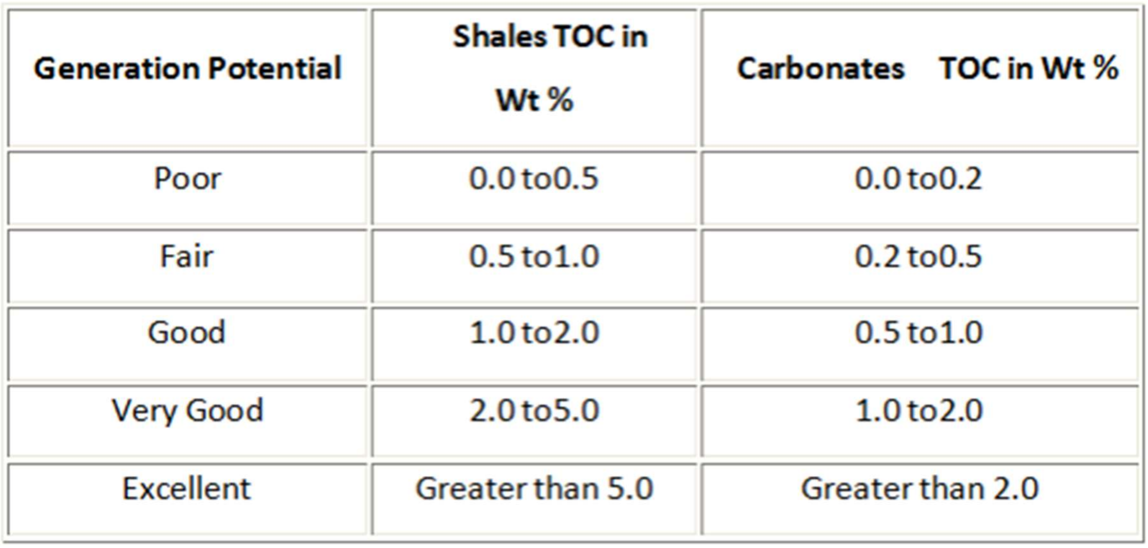
4 Determining source rock potential

The quantity of organic matter is commonly assessed by a measure of the total organic carbon (TOC) contained in a rock. Quality is measured by determining the types of kerogens contained in the organic matter. Thermal maturity is most often estimated by using vitrinite reflectance measurements and data from pyrolysis analyses**(Table 2)**.

4.1 Quantity of source rock: Total organic carbon (TOC) present in the source rock

4.2 Quality of source rock: Proportions of individual kerogens
Prevalence of long-chain hydrocarbons

4.3 Thermal maturity of source rock: Vitrinite reflectance
Pyrolysis Tmax



Generation Potential	Shales TOC in Wt %	Carbonates TOC in Wt %
Poor	0.0 to0.5	0.0 to0.2
Fair	0.5 to1.0	0.2 to0.5
Good	1.0 to2.0	0.5 to1.0
Very Good	2.0 to5.0	1.0 to2.0
Excellent	Greater than 5.0	Greater than 2.0

Table 2: Generation potential of source rocks(http://www.oilfieldknowledge.com/source-rock/)

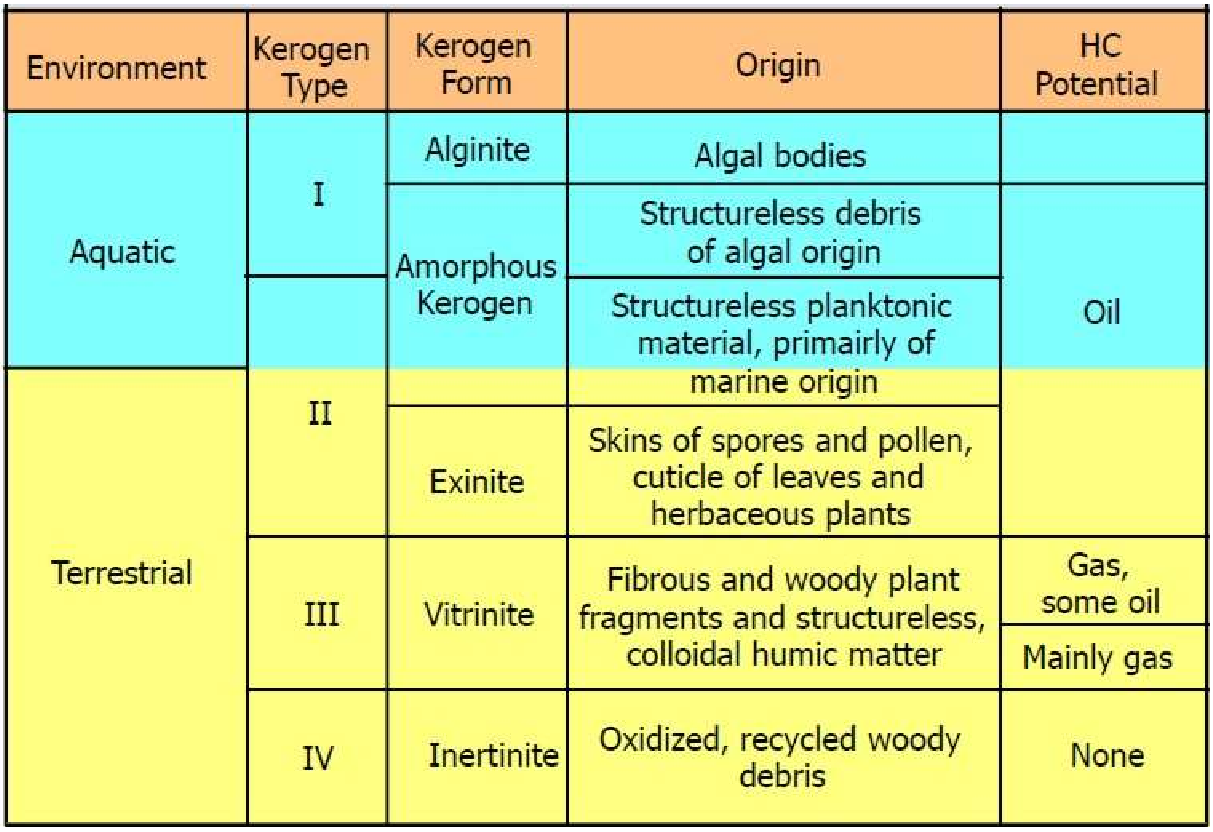
5 Types of source rocks

Source rocks are classified from the types of kerogens that they contain, which in turn governs the type of hydrocarbons that will be generated.

5.1 *Type 1:* source rocks are formed from algal remains deposited under anoxic conditions in deep lakes: they tend to generate waxy crude oils when submitted to thermal stress during deep burial.

5.2 *Type 2:* source rocks are formed from marine planktonic and bacterial remains preserved under anoxic conditions in marine environments: they produce both oil and gas when thermally cracked during deep burial.

5.3 *Type 3:* source rocks are formed from terrestrial plant material that has been decomposed by bacteria and fungi under oxic or sub-oxic conditions: they tend to generate mostly gas with associated light oils when thermally cracked during deep burial. Most coals and coaly shales are generally Type 3 source rocks.



Environment	Kerogen Type	Kerogen Form	Origin	HC Potential
Aquatic	I	Alginite	Algal bodies	
		Amorphous Kerogen	Structureless debris of algal origin	Oil
	II		Structureless planktonic material, primairly of marine origin	
Terrestrial		Exinite	Skins of spores and pollen, cuticle of leaves and herbaceous plants	
	III	Vitrinite	Fibrous and woody plant fragments and structureless, colloidal humic matter	Gas, some oil
				Mainly gas
	IV	Inertinite	Oxidized, recycled woody debris	None

Table 3: Type of kerogen and their hydrocarbon potential(http://www.oilfieldknowledge.com/source-rock/)

6 Maturation and expulsion

With increasing burial by later sediments and increase in temperature, the kerogen within the rock begins to break down. This thermal degradation or cracking releases shorter chain hydrocarbons from the original large and complex molecules occurring in the kerogen.

The hydrocarbons generated from thermally mature source rock are first expelled, along with other pore fluids, due to the effects of internal source rock overpressuring caused by hydrocarbon generation as well as by compaction. Once released into porous and permeable carrier beds or into faults planes, oil and gas then move upwards towards the surface in an overall buoyancy-driven process known as secondary migration(**Figure 9**).

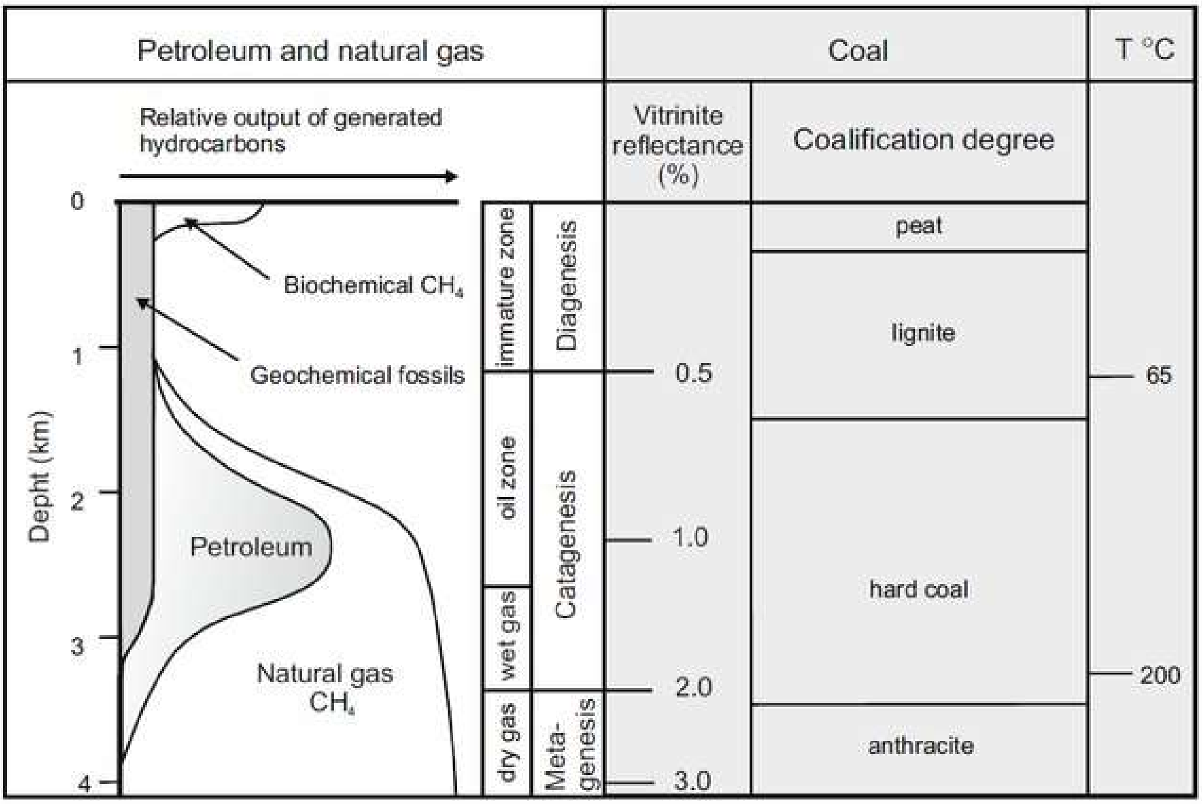


Figure 9. Organic matter maturity evolution through diagenesis, catagenesis and metagenesis, from Bahlurbg and Breitkreuz (2004)

7 Mapping source rocks in sedimentary basins

Areas underlain by thermally mature generative source rocks in a sedimentary basin are called generative basins or depressions or else hydrocarbon kitchens. Mapping those regional oil and gas generative "hydrocarbon kitchens" is feasible by integrating the existing source rock data into seismic depth maps that structurally follow the source horizon(s). It has been statistically observed at a world scale that zones of high success ratios in finding oil and gas generally correlate in most basin types (such as intracratonic or rift basins) with the mapped "generative depressions"**(Figure 10)**. Cases of long distance oil migration into shallow traps away from the "generative depressions" are usually found in foreland basins.Besides pointing to zones of high petroleum potential within a sedimentary basin, subsurface mapping of a source rock's degree of thermal maturity is also the basic tool to identify and broadly delineate shale gas plays.

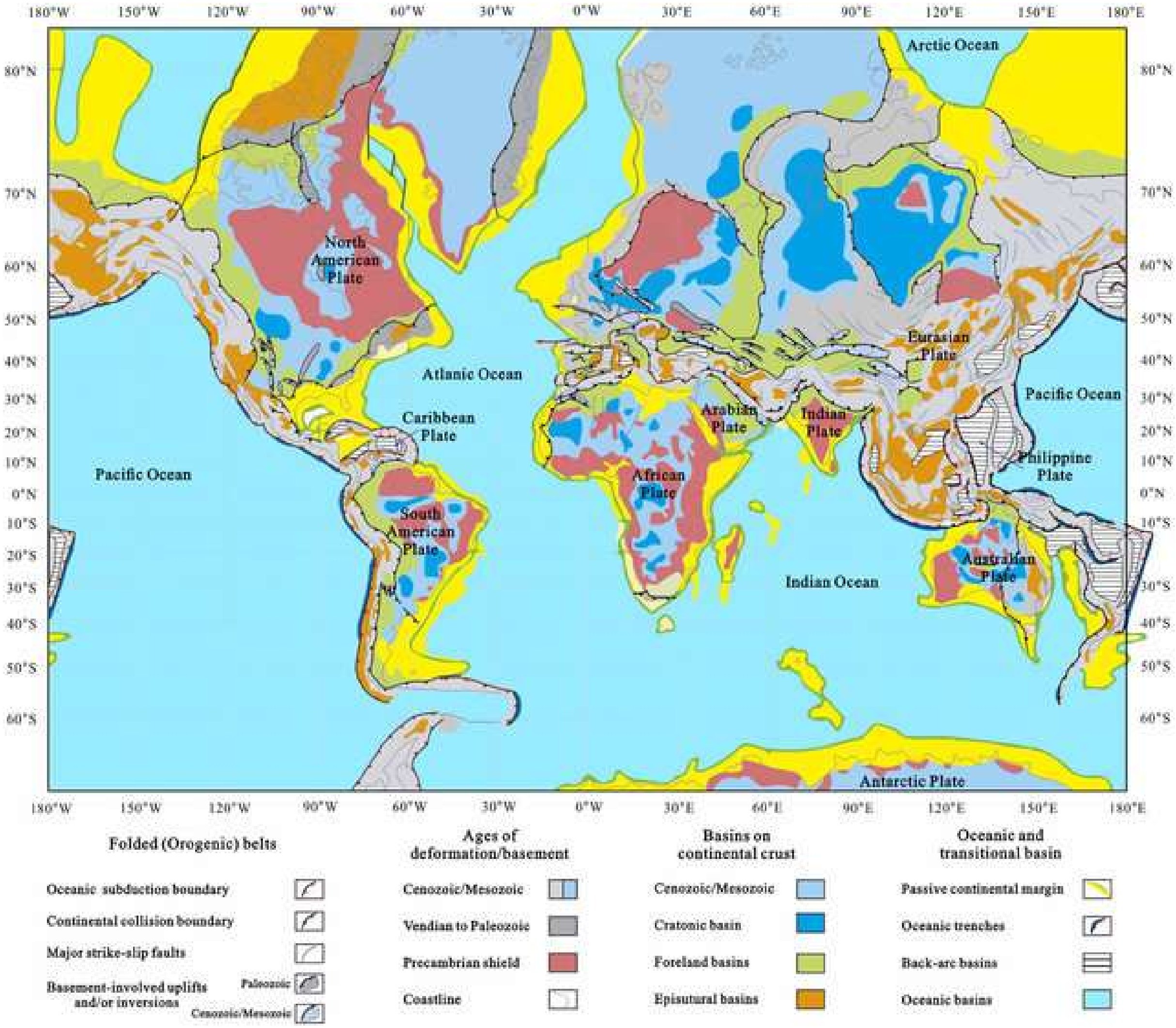


Figure 10.Sedimentary basins of the world (Roberts and Bally, 2012).

8 World class source rock

Certain source rocks are referred to as "world class", meaning that they are not only of very high quality but are also thick and of wide geographical distribution. Examples include:

- Middle Devonian to lower Mississippian widespread marine anoxic oil and gas source beds in the Mid-Continent and Appalachia: (e.g. the Bakken Formation of the Williston Basin, the Antrim Shale of the Michigan Basin, the Marcellus Shale of the Appalachian Basin).
- Kimmeridge Clay – This upper Jurassic marine mudstone or its stratigraphic equivalents generated most of the oil found in the North Sea and the Norwegian Sea.
- La Luna Shale – This late Cretaceous Turonian formation generated most of the oil in Venezuela.

- Late Carboniferous coals – Coals of this age generated most of the gas in the southern North Sea, the Netherlands Basin and the northwest German Basin.
- Hanifa Formation – This upper Jurassic laminated carbonate-rich unit has sourced the oil in the giant Ghawar field in Saudi Arabia.

CHAPTER III:

RESERVOIR ROCK

1 Introduction

Reservoir Rocks are the rocks that have ability to store fluids inside its pores, so that the fluids (water, oil and gas) can be accumulated. In petroleum geology, reservoir is one of the elements of petroleum system that can accumulate hydrocarbons (oil or gas). Reservoir rock must be having good porosity and permeability to accumulate and drain oil in economical quantities.

A fundamental property of a reservoir rock is its porosity. However, for it to be an effective reservoir rock, THE fundamental property is permeability. Both porosity and permeability are geometric properties of a rock and both are the result of its lithologic (composition) character. The physical composition of a rock and the textural properties (geometric properties such as the sizes and shapes of the constituent grains, the manner of their packing) are what is important when discussing reservoir rocks and not so much the age of the rock.

2 The properties of reservoir rocks

According to Society of Petroleum Engineers Glossary, a reservoir rock is a rock containing porosity, permeability, sufficient hydrocarbon accumulation and a sealing mechanism to form a reservoir from which commercial flows of hydrocarbons can be produced. Porosity and permeability are the reservoir rock most significant physical properties**(Figure 11)**.

A fundamental property of a reservoir rock between them is porosity. However, for explorationists, an effective reservoir rock, the most fundamental reservoir rock property is its permeability. Both of them are geometric properties are the result of its lithological, structural and compositional behavior (composition). These physical compositions of a rock and the textural properties are geometric such as sizes and shapes of the rock grains, their arrangement system and packaging.

The efficiency of reservoir rock account on different important properties, however in this paper discussing on reservoir rocks properties, porosity and permeability are main topics to focus on. Petroleum system is made of different elements which encompass reservoir rock. Moreover, it is found in a sedimentary basin whereby explorationists are able to study its stratigraphy and its sedimentology (rock history) to determine if there is a likeliness of the existence of petroleum system.

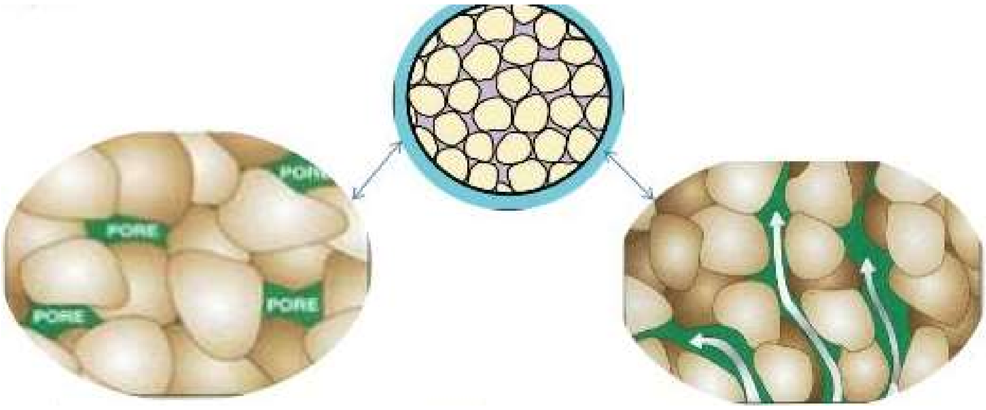


Figure 11.Reservoir rocks properties (Assignment I, 2014)

3 Types of reservoir rocks.

As a rock to be named a reservoir has to be a porous and permeable lithological structure. It encompasses sedimentary rocks. These sedimentary rocks may be made of sandstones (quartz sand or arksosic sandstone), carbonates mud or dolomite. Dolomites mostly form good reservoirs because the common reason behind it is that there is Mg, 13% smaller than Ca in a way that during dolomitization, there is a total decrease in volume of the material by 13%, here by 13% porosity is gained**(Figure 12)**.

3.1 *Sandstone reservoir rocks:* The term sand refers to a specific grain with sizes between (62 µm – 2 mm). The performance of the sandstone as a reservoir rock is described by its combination of porosity and permeability depending on the degree to which the sand dominates its. The favorable texture is depicted by packaging of similar sized grains, not a combination of coarse- and fine-grained composition. The best sandstone reservoirs are those that are composed mainly of quartz grains of sand size of nearly equal sizes or silica cement, with minimal fragmented particles.

3.2 *Carbonate reservoir rocks:*The most fascinating aspects of carbonate reservoir rocks are their content. Carbonates are usually made of fossils which “range from the very small single cell to the larger shelled animals”. Most carbonate rocks are deposited at or in very close neighborhood to their site of creation. The "best-sorted" carbonate rocks are Oolites in which encompass grains of the same size and shapes even though Oolites are poorly sorted.

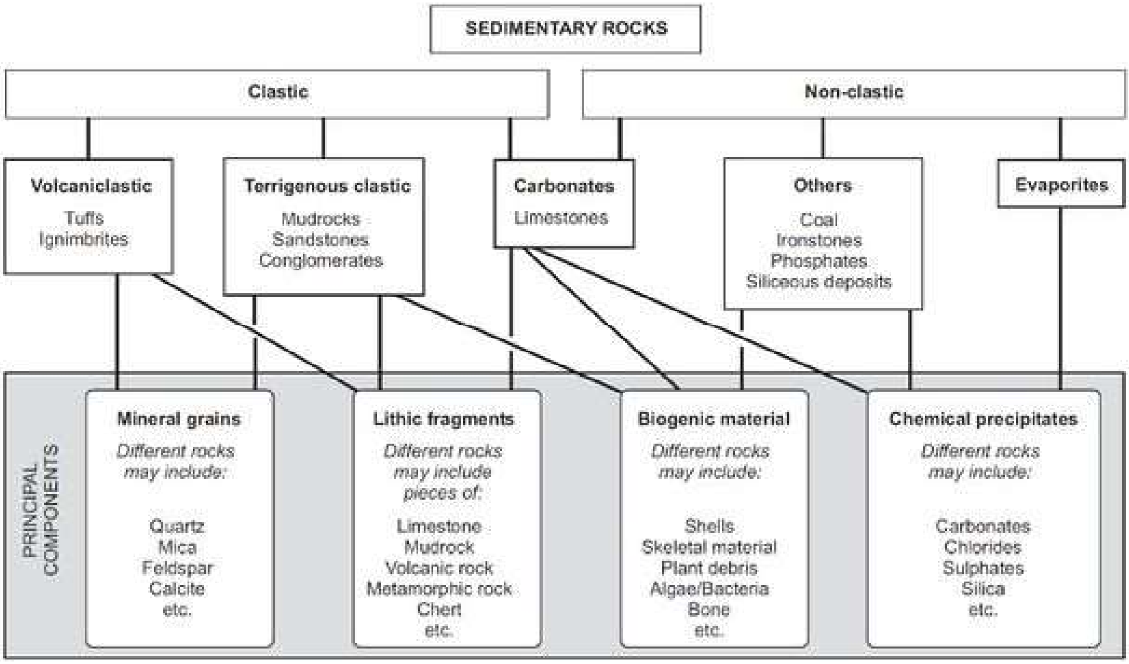


Figure 12. Scheme of classification of reservoir rocks. (Adapted from Nichols,2009, from lecture handout by Alamsyah).

3.3 *Siliciclastic Reservoir:* Siliciclastic sedimentary rocks are the most abundant of the sedimentary rock. They are formed from the detritus left over from the weathering of igneous, metamorphic, and older sedimentary rocks**(Figure 13)**.

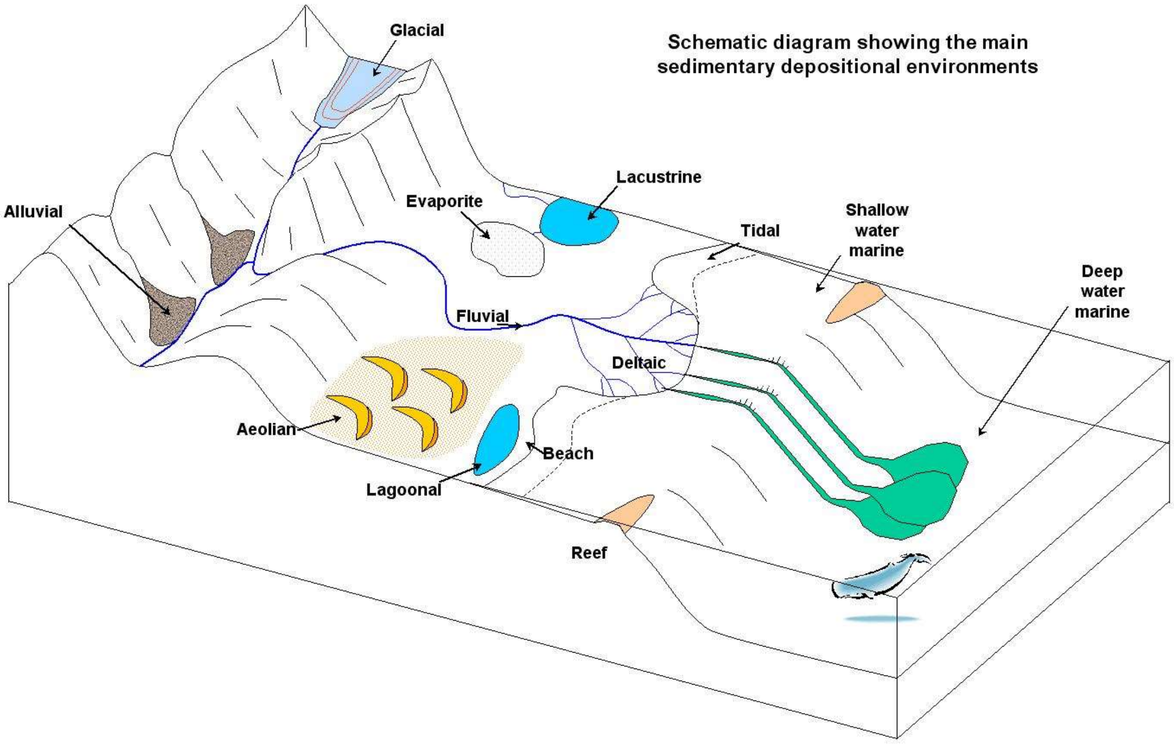


Figure 13.Schematic diagram showing the main, sedimentary depositional environments (https://wiki.aapg.org/Reservoir)

3.3.1 Shallow and Deep Marine Reservoir

Hydrocarbon reservoir can be divided into two groups. There are clastic sedimentary rock and non-clastic sedimentary rock. On the clastic sedimentary, contained some precipitation area, as one in marine area. Rock Type can be formed in deposition marine areas such as shelf sandstone and turbidity sandstone.

3.3.1.1 Shelf sandstones: formed from precipitating in the shallow marine area. Sands transported by water current from river to shallow marine area. Because of that process, has been formed sands body around the grow delta and maybe form the fan like in delta.

3.3.1.2 Turbidity sandstones: rock formed in deep marine area with rotation force existing rotation deep current so as formed the coarse layer which has interaction with shale layer in the deep marine. Shape from deposition of turbidity sandstones can be like a lens, duct, or fans.

3.3.2 Lacustrine Reservoir: This type of reservoir formed in basin containing water surrounded by land and initially formed by tectonic processes, volcanic, rifting, soil movement, and the erosion by the wind on the coast or in land. The texture of sedimentary rocks in the environments usually granules grained and the size between 2 mm – 4 mm.

3.3.3 Eolian Reservoir: Formed in large areas with the accumulation of sand deposition. The sediment resulting from wind-blown sand**(Figure 14)**. The clastic texture of the environment is granules (2 mm – 4 mm) and coarse (over 2 mm).

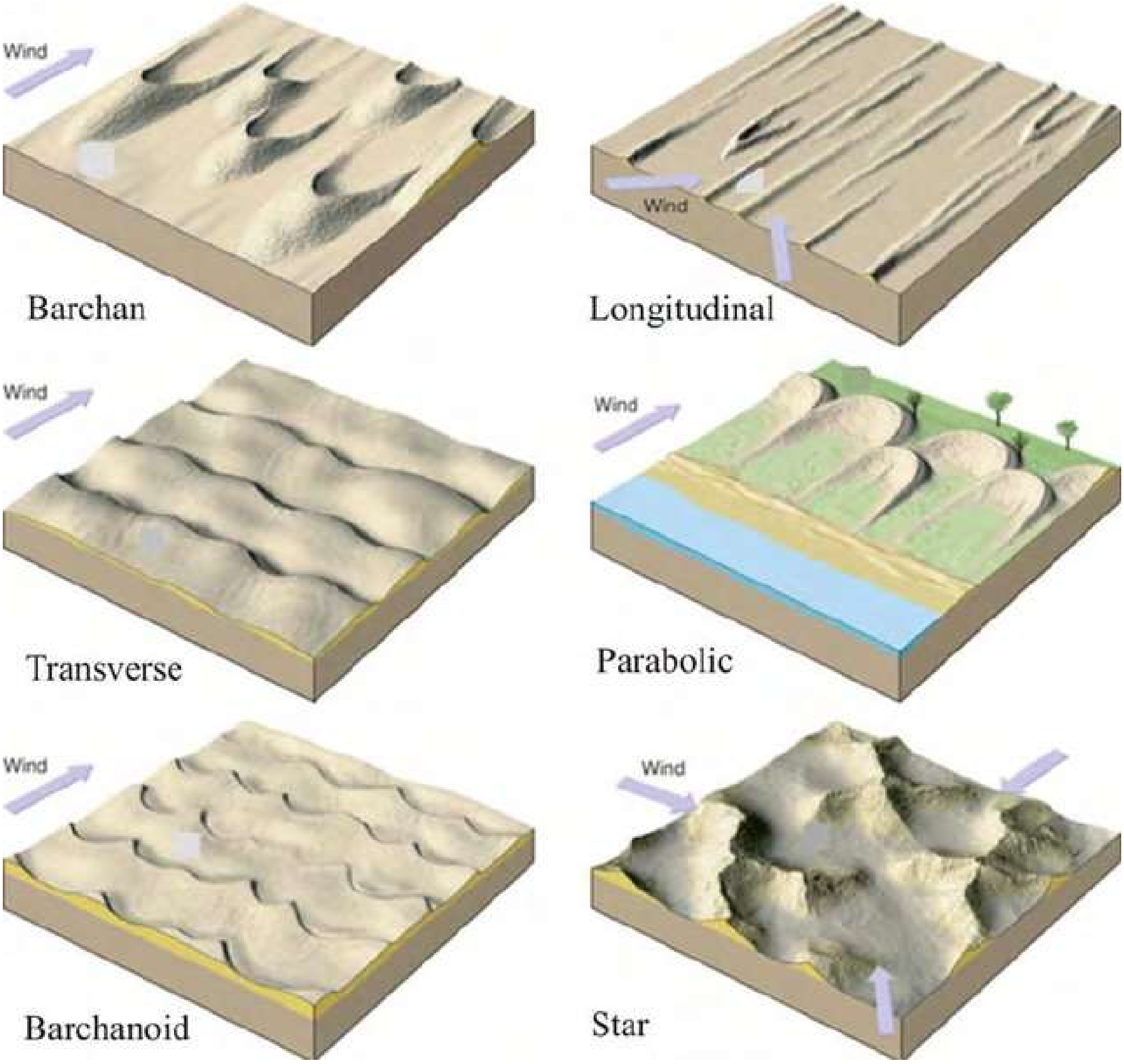


Figure 14. Schematic diagram showing the eolian depositional environment (https://wiki.aapg.org/Reservoir)

3.3.4 *Fluvial Reservoir:* Type reservoir generated by the flow of the river where the process is formed by 3the erosion, transport and deposition of forming depositional formation**(Figure 15)**.

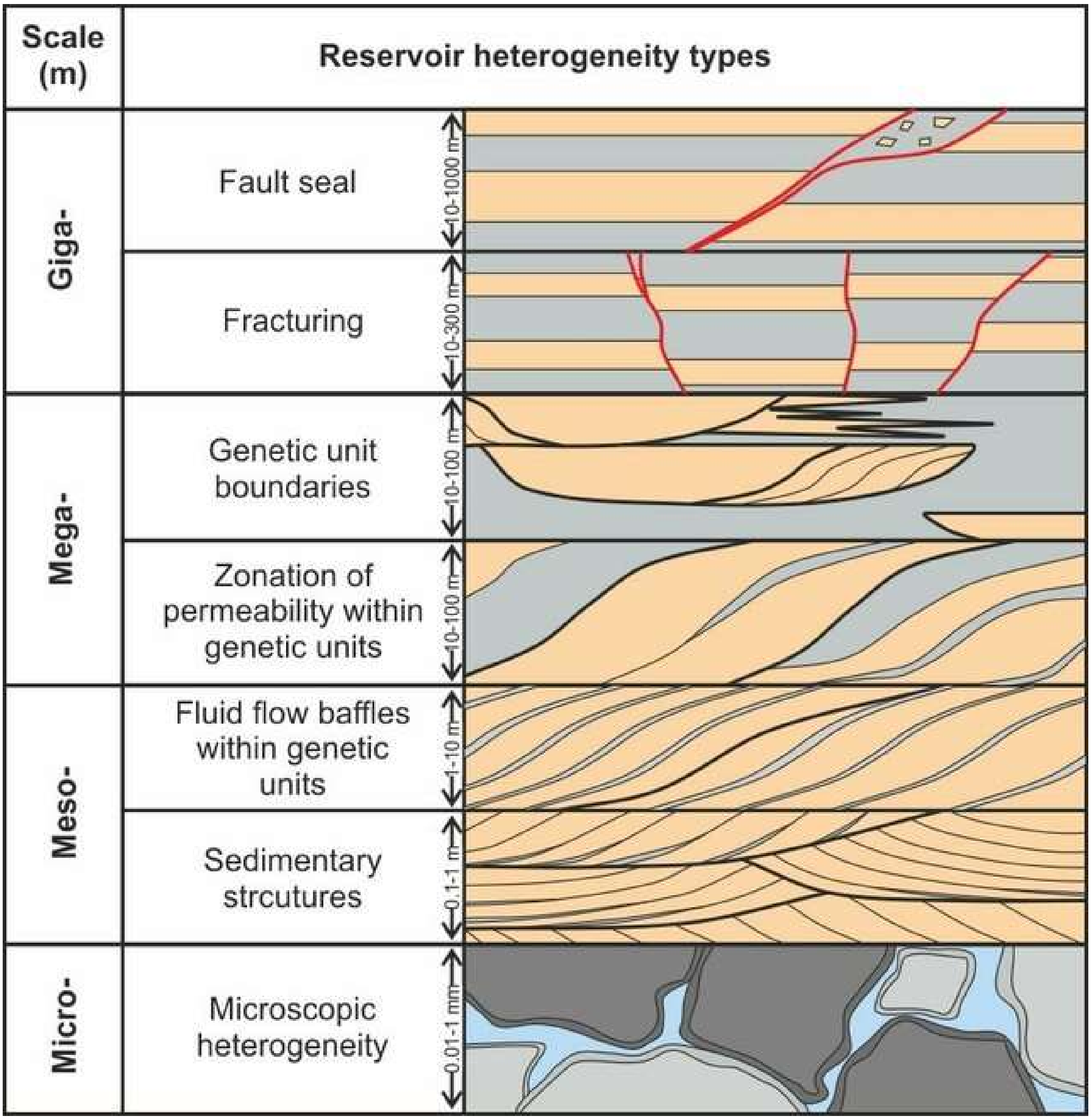


Figure 15.The scales of fluvial reservoir heterogeneity, adapted from Tyler and Finley (1991) and Morad et al. (2010)

3.3.5 *Deltaic Reservoir:* On this type of reservoir, it was formed by the accumulation of lacustrine sediments**(Figure 16)**. Very fine grain sediment rocks.

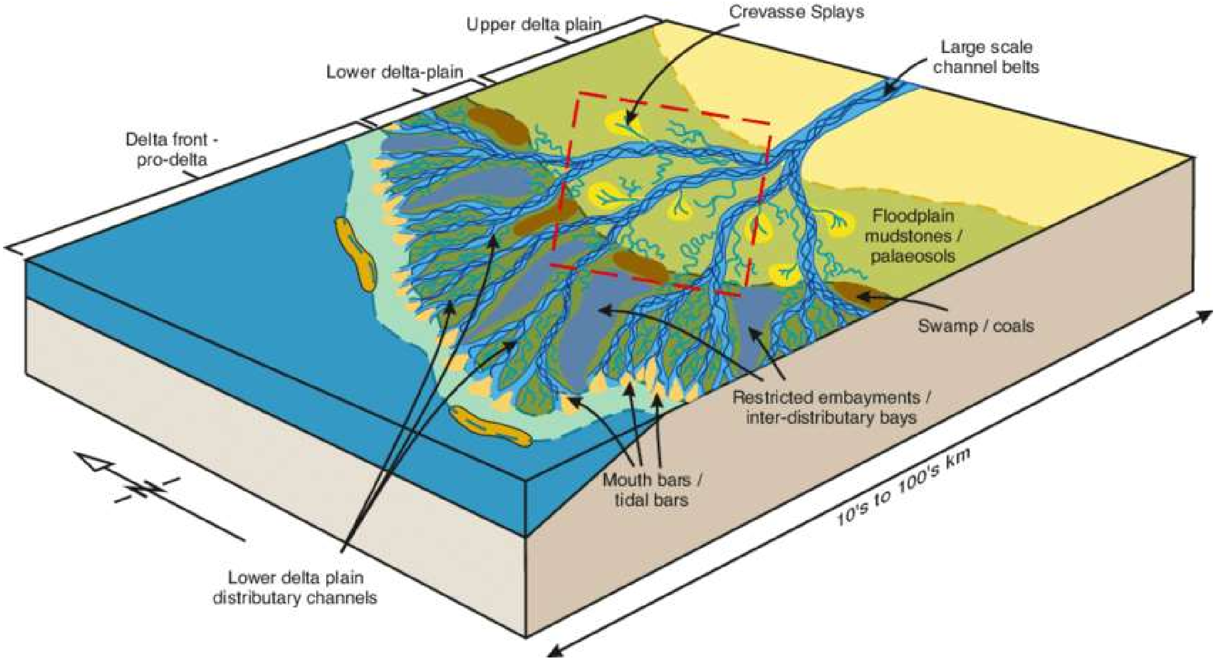


Figure 16. Schematic diagram showing the Deltaic depositional environment (https://wiki.aapg.org/Reservoir)

3.3.6 *Carbonate Reservoir:* Adapted from Alamsyah Carbonate rocks is a sedimentary rock with carbonate fraction more than 50%. Carbonate rocks can be used as a reservoir because of its porosity and permeability **(Figure 17)**. Carbonate rocks can be classified to clastic and non-clastic sediment. Its environmental formation is Tropic Ocean. The porosity concept of a carbonate rock might be a little bit more complex than other rocks, because of it vary secondary porous, from carbonate dissolution made from skeletal remain and microbe with cement. Almost all of carbonate reservoir type accumulated as a shallow marine sedimentary, except on a pelagic chalk and deep marine resediment reservoir carbonate in Mexico seas. Carbonate reservoir rocks can be found as a clastic limestone, carbonate framework (reef), and dolomite.

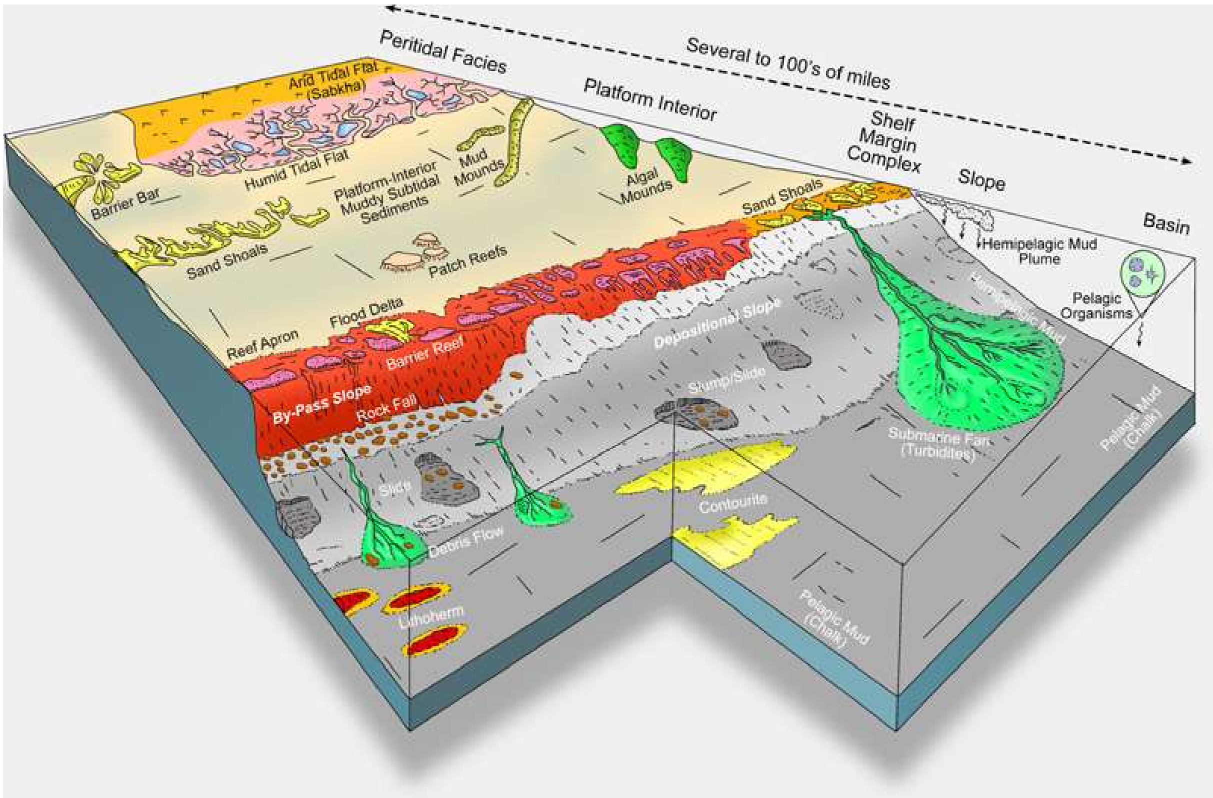


Figure 17. Generalized carbonate depositional model (https://www.beg.utexas.edu/lmod/_IOL-CM01/103103_PREFINAL/cm01-step10.htm#)

3.3.7 Reef Reservoir: Reef is a framework made of sea organism containing skeletal, grow in shallow clean water where sunlight can reach as nutrition. Reef distribution is varying, some on the edge of the shelf and become a barrier, some scattered called patch reef. Patch reef can reach a few kilometer sizes while barrier can be elongated along the edge and limit the exposure with basin. Meanwhile the shape of a reef can be a pole (pinnacle) or lengthened (fringing). Both can become a good reservoir(**Figure 18)**. Reef is a non-clastic carbonate rocks without transportation process on its formation.

Figure 18. Reef habitat in the shallow sea. Adapted from Alamsyah

3.3.8 *Clastic Limestone:* Clastic limestone usually associated with oolit and become a pretty good reservoir. Limestone associated with oolit often referred to as calcarenite. The Deposition is in shallow marine environments along the coast with high energy (strong wave currents). Porosity may be extremely high because of the dissolution, but permeability is not far from 5 milidarcy. It is called clastic because oolit associated with limestone is present through the transport process before finally deposited. Dolomite formed by processes of calcite dolomitization from other carbonates (e.g. limestone). Dolomitization occurred not long after the process of sedimentation. Dolomitization process can be reviewed as the secretion of magnesium contained in sea water into the compounds associated with carbonate Dolomite production begins from the Pre-Cambrian, continued from Paleozoic to Mesozoic, up to Tertiary time. Calcite will be replaced with the dolomite compound that has smaller volume, so that the space between the pores of the rock grew wide.

3.3.9 *Another Type of Reservoir:* Although the porosity and permeability are poor, shale, silt stone, limestone can even act as reservoir due to fractures in the rock body (secondary porosity – secondary permeability). For example, an oil field in Florence, Colorado which is having shale (Lower – Upper Cretaceous) as reservoir rock.

Then, it shows that for other than sedimentary rocks (igneous – metamorphic) could be reservoir rock if there are in fracturing state. For example, in Cuba, the oil is obtained from ultra-base igneous rock or volcanic rock that has fractured**(Figure 19)**. There are eight oil fields in Cuba in 1964 that produce 710 barrels oil per day. Reservoir from this type has a very small percentage compared to the reservoir from sedimentary rock (about 1% of the overall reservoir in the world)

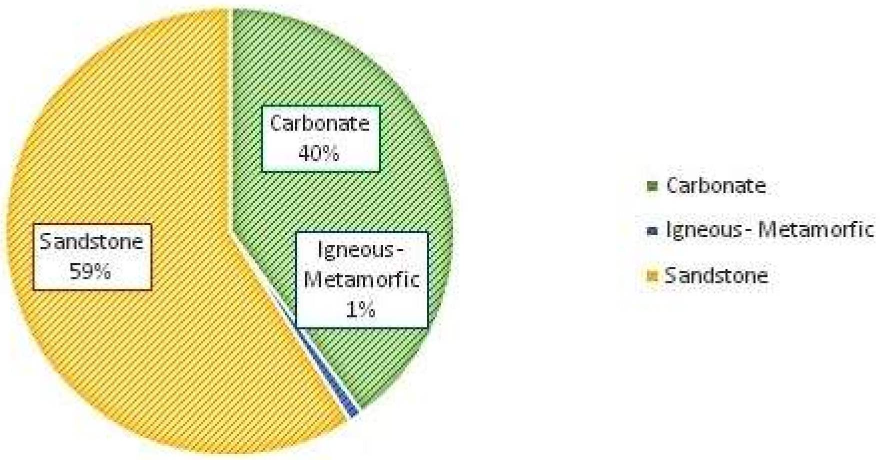


Figure 19. Comparison of reservoir rock types around the world in 1956 (based on Knebel & Rodriguez, 1956 in Koesomadinata, 1980)

4 Reservoir rock properties, interpretations and their significance on a petroleum system.

4.1 *Porosity:*Reservoir porosity is the property that tells how porous a rock is. It is also defined as a measure of the capacity of reservoir rocks to contain or store fluids(**Figure 20)**. The porosity is genetically classified basing on standard sedimentologic description of reservoir rock; there are primary and secondary porosity.

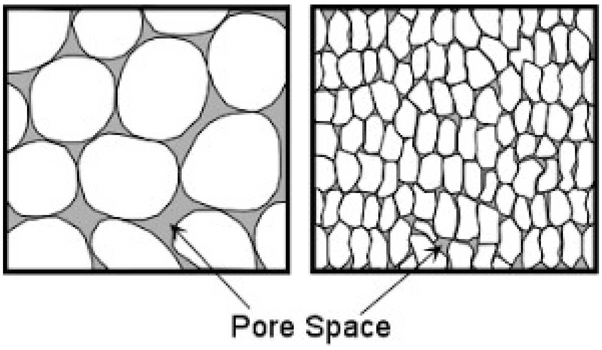


Figure 20.pore space (https://wiki.aapg.org/Reservoir)

4.1.1 *The primary porosity:* types are**(Figure 21)**:

4.1.1.1 *Inter-particle porosity:*In this type by which rock content was quickly lost in muds and carbonate sands through compaction and cementation respectively. This type is mostly found as siliciclastic sands.

4.1.1.2 *Intra particle porosity:* by which the porosity is made of interiors of carbonate skeletal grains.

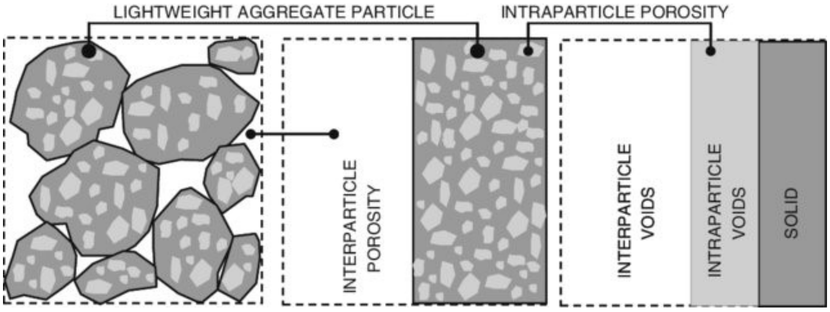


Figure 21. Inter and intra-granular porosity (adapted fromholm et all. 2001)

4.1.2 *Secondary porosity:* It is the porosity formed after deposition leads to other couple of reservoirs types**(Figure 22)**:

4.1.2.1 *Dissolution porosity:*is made of carbonate dissolution and leaching. It is also called carbonate reservoirs.

4.1.2.2 *Fracture porosity:* is characterized by not being voluminous.

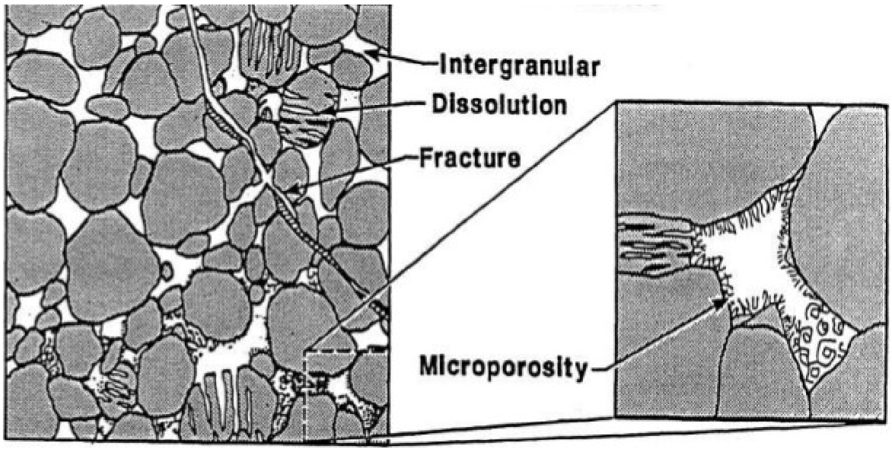


Figure 22. Basic porosity types (https://wiki.aapg.org/Reservoir)

Porosity can also be classified basing on rock morphology. There are three types of morphologies to the pore spaces which are(**Figure 23**):

- Caternary in which the pore open to more than one throat passage.
- Cul-de-sac in which the pore open to only one throat passage.
- Closed pore in which there is no connection with other pores.

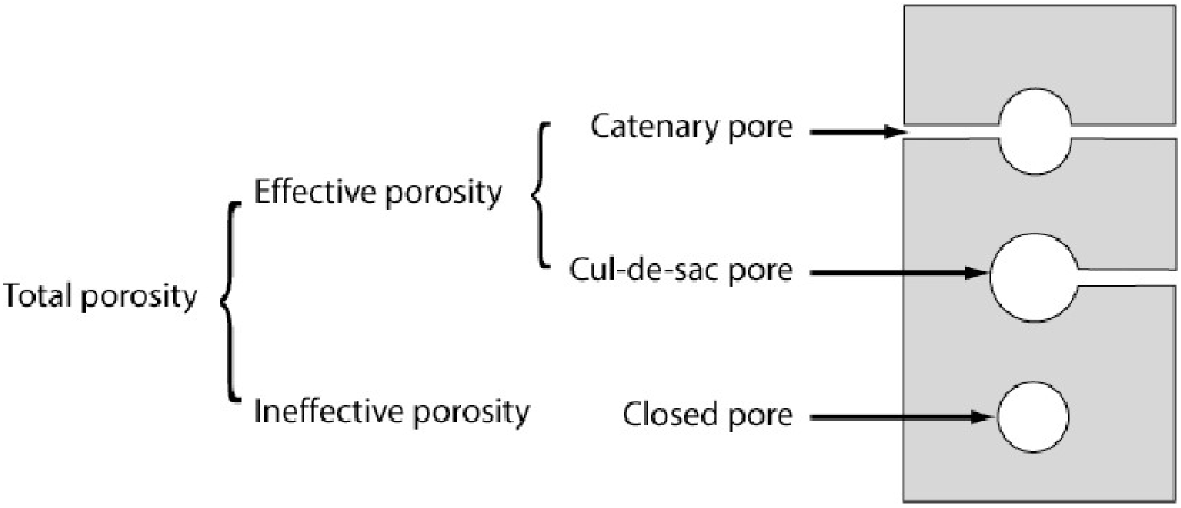


Figure 23.Schematic diagram illustrating the three basic pore-types, which define the effective porosity open for flow (From Selley, 1985).

4.2 *Permeability:* is a measure of the ability of a fluid to pass through its porous medium(**Figure 24**). Permeability is one of important to determine the effective reservoir.

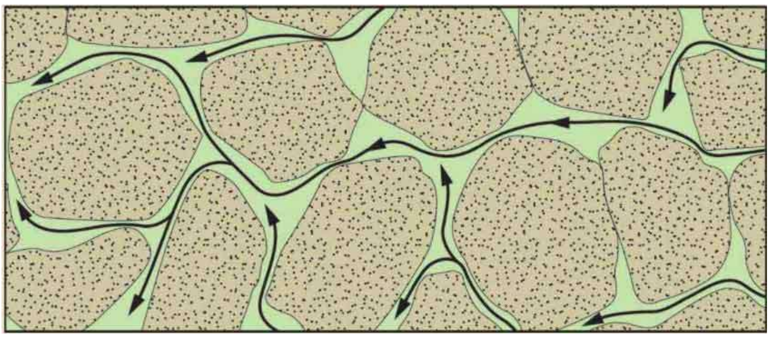


Figure 24.The importance of connectivity. Connected pores (green) give rock its permeability, allowing fluid to flow (black arrows)(https://wiki.aapg.org/Reservoir)

Porosity and permeability are two properties describing the reservoir rock capacity with regard to the fluid continence. Moreover, a reservoir rock can be porous without being permeable. For example, it is said to be permeable if and only if the pores "communicate".

Hence for explorationists, knowing reservoir rock permeability is a key mile stone because it is important for being used to determine if it really has sufficient commercial accumulation of oil, indeed measuring it is very difficult.

When there is only one type of fluid flowing through porous media, the permeability for this case is called "absolute permeability." However, when there is more than one type of fluids present in a rock, a permeability of each fluid to flow is decreased because another fluid will be moving in the rock as well. A new term of permeability called "effective permeability" is a permeability of a rock to a particular fluid when more than one type of fluid is in a rock

Reservoir consists of three fluids (gas, oil, and water) so these are commonly used abbreviations for effective permeability for each fluid.

- kg = effective permeability to gas
- ko = effective permeability to oil
- kw = effective permeability to water

Normally, it is common to state effective permeability as a function of a rock's absolute permeability. Relative permeability is defined as a ration of effective permeability to an absolute permeability of rock**(Figure 25)**. The relative permeability is widely used in reservoir engineering. These functions below are the relative permeability of gas, oil, and water.

- krg = kg ÷ k
- kro = ko ÷ k
- krw = kw ÷ k

k = absolute permeability

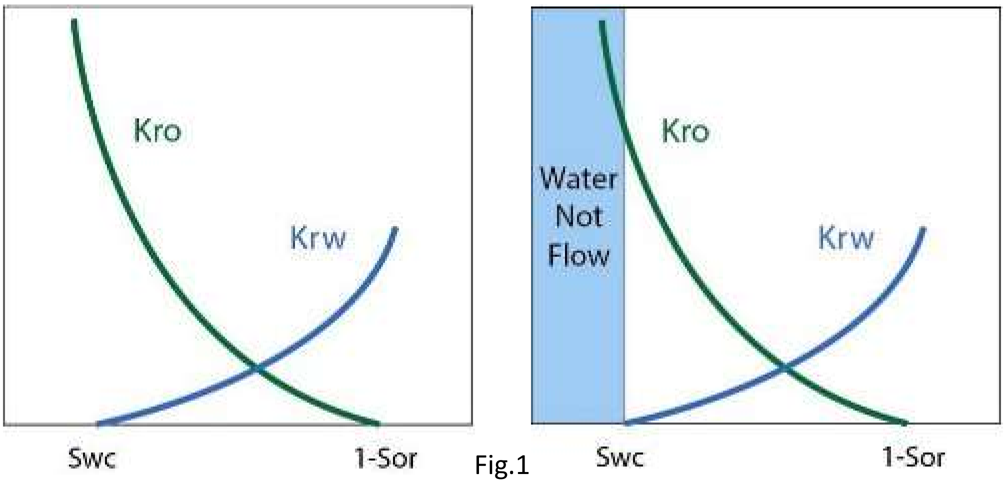


Fig.1 Fig.2

Figure25. demonstrates a plot of oil-water relative permeability curves. Relative permeability is normally plotted as a function of water saturation in a rock (S.A. Abu-Khamsin 2016).

5 Other factors affecting the volume of the reservoir rocks.

5.1 *Grain size and pattern arrangement:* Apart from the arrangement pattern of grains size which effect rock properties, the actual size of the grains does not affect the permeability of a neither reservoir rock nor porosity.

5.2 *Shape of the grains:* grains with high sphericity tend to pack themselves well to make a minimum pore space, the fact which increases angularity and hence pore space volume increases.

5.3 *Sorting or uniformity of size of the grains:* size of grains has an effect on reservoir properties; the more uniform the grains are sized, the great proper volume of voids spaces. Thereby mixing grains of different sizes tends to decrease total volume of void space.

5.4 *Subsequent action to the sediments (compaction):* The more grains are compacted, more the volume of void spaces decreases. However, the compaction of sand is less effective than the way clay does.

5.5 *How the grains were formed.*

6 Methods for determining rock properties.

Reservoir rock properties such as porosity and permeability are directly or indirectly measured. The direct methods consist of measuring the core sample taken from the parallel lithological area of the reservoir rock to assess them while the indirect methods consist of using data collection, well logs, seismic, production tests, etc., the porosity data are used in the basic reservoir to evaluate volumetric calculation of fluids in the reservoir and calculating fluid saturations and geologic characterization of the reservoir**(Table 4)**.

6.1 *Porosity:* is the void space in a rock that can store the fluids. It is measured as either a volume percentage or a fraction (expressed as a decimal). In the subsurface this volume may be filled with petroleum (oil and gas), water, a range of non-hydrocarbon gasses (CO2, H2S, N2), or some combination of these. Porosity is symbolized in phi (ϕ) and its value is expressed in percentage. Porosity value calculation:

$$\emptyset = \frac{\text{pore volume}}{\text{bulk volume}} \times 100\%$$

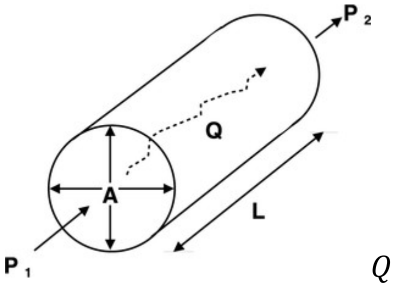
Porosity divided into two types, absolute porosity and effective porosity. Absolute porosity is the ratio of the total pore volume in the rock to bulk volume, obtained by the calculation:

$$\emptyset a = \frac{\text{total pore volume}}{\text{bulk volume}} \times 100\%$$

Effective porosity is the ratio of interconnected pore volume to bulk volume, obtained by calculation:

$$\emptyset e = \frac{\text{total interconnected pore volume}}{\text{bulk volume}} \times 100\%$$

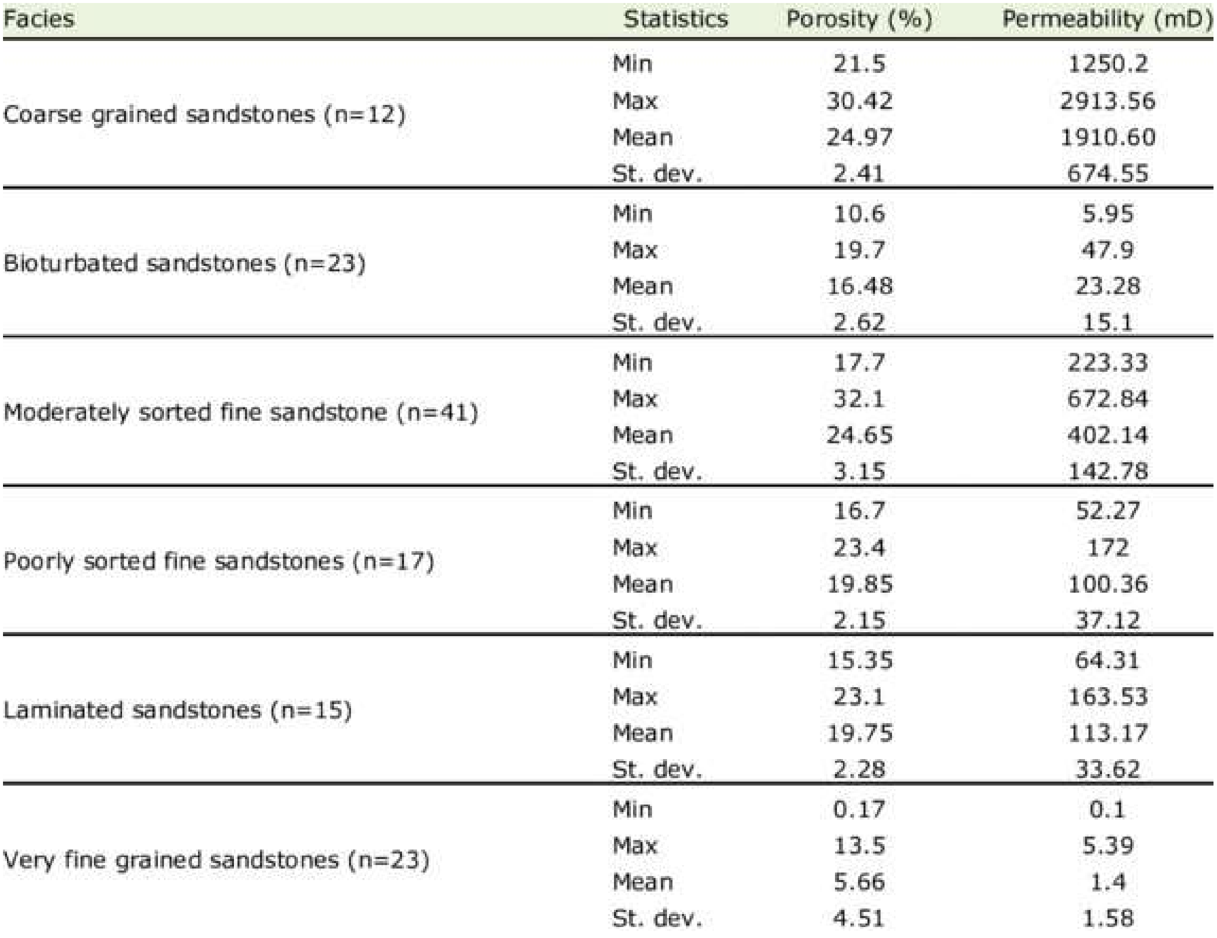
*6.2 Permeability:*Permeability is an intrinsic property of a material that determines how easily a fluid can pass through it. In the petroleum industry, the Darcy (D) is the standard unit of permeability, but milidarcies (1 mD = 10-3 D) are more commonly used. A Darcy is defined as a flow rate of 10-2 ms-1 for a fluid of 1 cp (centipoise) under a pressure of 10-4atm m-2. Permeability in reservoir rocks may range from 0.1 mD to more than 10 D.



$$Q = KA\frac{\Delta h}{L}$$

With:

q representing flow rate, A the area section of pores, µ represents viscosity constant of fluid and dp/ dL represents the infinitesimal change of flowing pressure.



Facies	Statistics	Porosity (%)	Permeability (mD)
Coarse grained sandstones (n=12)	Min	21.5	1250.2
	Max	30.42	2913.56
	Mean	24.97	1910.60
	St. dev.	2.41	674.55
Bioturbated sandstones (n=23)	Min	10.6	5.95
	Max	19.7	47.9
	Mean	16.48	23.28
	St. dev.	2.62	15.1
Moderately sorted fine sandstone (n=41)	Min	17.7	223.33
	Max	32.1	672.84
	Mean	24.65	402.14
	St. dev.	3.15	142.78
Poorly sorted fine sandstones (n=17)	Min	16.7	52.27
	Max	23.4	172
	Mean	19.85	100.36
	St. dev.	2.15	37.12
Laminated sandstones (n=15)	Min	15.35	64.31
	Max	23.1	163.53
	Mean	19.75	113.17
	St. dev.	2.28	33.62
Very fine grained sandstones (n=23)	Min	0.17	0.1
	Max	13.5	5.39
	Mean	5.66	1.4
	St. dev.	4.51	1.58

Table 4: Porosity and permeability statistics of the different facies (S.A. Abu-Khamsin 2016)

CHAPTER 4:

CAP ROCKS

1 Introduction

Cap rock is a rock that prevents the flow of a given fluid at a certain temperature and pressure and geochemical conditions**(Figure 26)**.

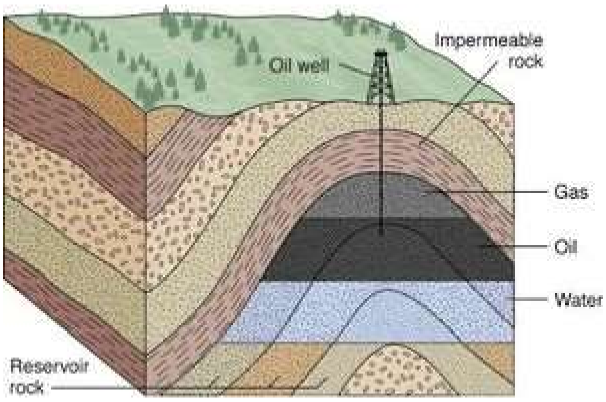


Figure 26. An anticline oil and gas reservoir. The cap rock would be the impermeable rock layer(S. Herron 2010).

For a long time, the only force causing the movement of oil and gas in the subsurface was believed to be buoyancy. If so, then to form oil and gas accumulation, their migration paths must have been stopped by a roof, i.e., caprock (seal). Clays, shales, carbonates, evaporites, and their combinations can form caprocks.

The same rocks react differently to different fluids. In some cases, rocks serve as satisfactory or good conduits for water, but form barriers for oil or gas movement. In some other situations rocks yield oil but stop gas movement, etc. This is determined by capillary forces, the magnitude of which depends on fluid and rock properties (fluid density, fluid viscosity, rock structure, rock wettability) and pore size (capillary forces almost disappear when the pore diameter exceeds 0.5mm).

2 Types of cap rock in petroleum system

2.1 *Type I:* Caprocks are typical for argillaceous sequences in a state of continuing compaction; they are developed in areas of young subsidence of Earth’s crust, with abnormally high pore water pressure. Sealing properties of these rocks are determined by the amount of capillary pressure at the contact of the reservoir and caprock, the pore pressure of water saturating the caprock, initial pressure gradient of water and the variation of hydraulic forces in the section. Oil and gas accumulations have higher potential energy than that of the formation water. These accumulations can be stable only if this energy is equal to or less than the caprock breakthrough energy. Pore water pressure in compacting argillaceous beds is always greater than the pressure in the adjacent reservoir beds. As a result, sealing capability of the Type I caprocks is determined by hydraulic sealing, by the amount of capillary pressure, and by the pressure at which water begins to flow through caprocks. Just the capillary pressure alone in such caprocks may exceed 100kg/cm2. This means that the Type I caprocks is capable of confining an oil accumulation having almost any column height. It appears that sealing capability of argillaceous caprocks does not depend on their thickness describes only the aforementioned caprock type.

2.2 *Type II:* Caprocks are associated with rocks compacted beyond the plasticity limit and having lost ability to swell on contact with water. Such rocks do not contain swelling clay minerals, and interstitial water contains surfactants. Consequently, pore water in these rocks does not have initial pressure gradient. This type of caprocks is encountered mostly in the Paleozoic and Mesozoic sediments of young and old platforms. There are no clear-cut overpressure environments there, but there is a relatively clear hydrodynamic subdivision in the section. the hydrodynamic environment may improve or lower the sealing capability of caprocks. In an extreme case, the water potential in the reservoir may exceed the water potential of the bed overlying the caprock by the value of capillary pressure.In such a situation, the caprock will be open for the vertical flow of hydrocarbons, and the trap will not exist even when potential distribution in the reservoir bed is favorable.

2.3 *Type III:*Caprocks are typical for rocks with a rigid matrix and intense fracturing. Such caprocks are mainly developed over the old platforms in regions of low tectonic mobility, with no detectable hydrodynamic breakdown of the section. Formation water potential in such regions is practically equal throughout the section and corresponds to the calculated hydrostatic potential. The correlation between clay mineralogy and their

> sealing properties are as follows "The permanency in the composition of the silicate layer is a characteristic of the kaolinite group minerals. As a result, replacements within the lattice are very rare and the charges within a layer are compensated. The connection between silicate layers in the C-axis direction is implemented through hydrogen atoms, which prevents the lattice from expanding, ruling out the penetration of water and polar organic liquids. The silicate layer in the montmorillonite mineral group is variable due to a common isomorphic replacement in octahedral and narrower tetrahedral sheets. This replacement results in the disruption of the lattice neutrality.

N.B.A very important information for the evaluation of the role water plays in the formation of sealing properties is the knowledge of the structural status of the layer in an immediate contact with the particles surface, and the role the cations having different charge density play in the preservation of water molecules structure. Carbonates with a substantial clay content have laminated texture. As a rule, this results in a deterioration rather than an improvement of sealing properties due to the emergence of weakness zones at the contact between different lithologies. Evaporite seals, which are common, include salt, anhydrite, and sometimes shales.It is a common (and probably erroneous) belief that such seals are the best and most reliable. Brittleness of these rocks at the surface conditions contradicts that belief. Besides, cores recovered in the Dnieper-Donets Basin and North Caspian Basin display macro- and microscopic fractures, which sometimes cut monolithic salt crystals. The fractures may be healed by secondary salt, but often contain traces of oil and sometimes gas bubbles. The reliability of caprock is not directly related to its thickness. Thus, properties of evaporites as seals change widely during the catagenesis (and in time). Similar changes also affect the other types of seals albeit not so obviously. Inclusions, such as organic matter, silt, clay or carbonate particles degrade sealing properties of evaporites due to the formation of zones of weakness around such inclusions.

7 Characteristics of the Caprock:

A large amount of expertise regarding caprock performance is available from hydrocarbon exploration, production, and storage operations. However, while there are many similarities in seal performance criteria, there are also key differences that must be considered when storage of CO2 is being evaluated, as a caprock that is adequate for hydrocarbon storage may not be adequate for CO2 storage. For example, in terms of seal capacity and resistance to fracturing, the most effective sedimentary seals for hydrocarbons are gas hydrates followed by evaporites In comparison, methane gas hydrates should not under any circumstances be considered as a potential seal for CO2 storage reservoirs due to the high probability of an exchange reaction occurring, indeed they should be classed as a geohazard and avoided.

To form an effective seal for CO2 storage purposes the sealing lithology needs to be:

- impermeable to CO2
- unfaulted and relatively ductile (resistance to fracturing)
- laterally continuous, maintaining a constancy of properties over a large area

8 Faulting &Fracturing:

The caprock should ideally be unfaulted, as faults could provide migration pathways for the CO2 to leak out of the reservoir. Thus, extensively faulted and fractured sedimentary basins are not good candidates for CO2 storage, unless the faults and fractures are sealed (closed) and CO2 injection will not reopen them (Bachu, 2005). It is this selection criterion that makes seismically active areas unattractive as potential storage targets (Bachu, 2005).

In some situations, for example in faulted halite layers, faults can become resealed, and therefore do not present a migration pathway. Other types of sealed faults also exist (e.g. clay or shale fault smears or gouges), and are indeed often responsible for the formation of structural traps. However, their sealing nature would need to be confirmed by detailed analysis to ensure the integrity of the storage site.

In some instances, while the fault itself is effectively impermeable and sealed to lateral cross-fault flow, there may be a high permeability damage zone in the adjacent rocks that will act as a migration pathway through the top seal (e.g. CO2 leakage in the northern Paradox Basin, Utah; Shipton et al., 2005). As highlighted by Fisher & Knipe (2001), there is a lack of definitive models to explain why in some circumstances faults act as conduits for fluids, whereas in others they form barriers.

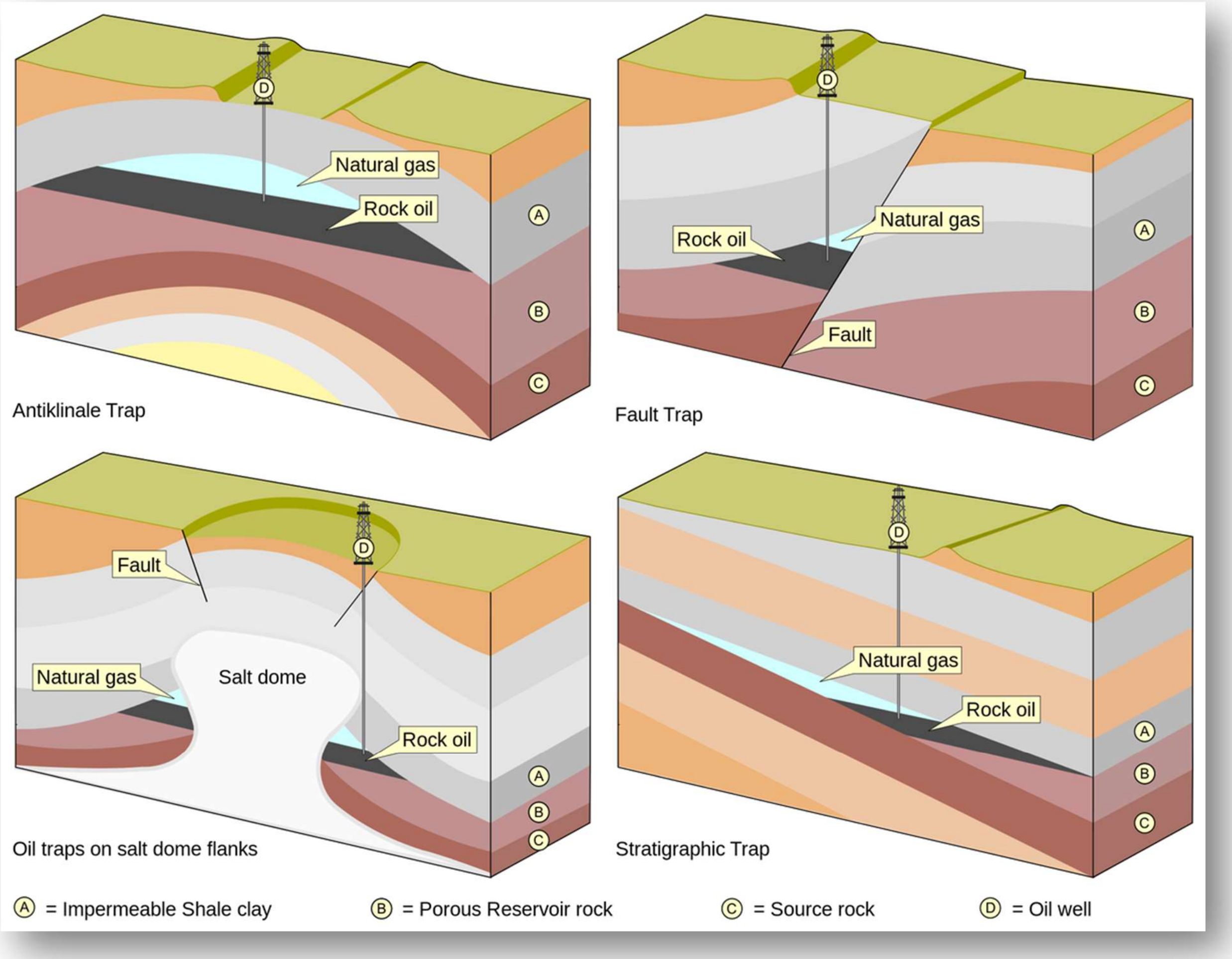
9 Seal Thickness and Continuity:

Theoretically, the thickness of a seal does not contribute to seal capacity. In reality, a bed only a few cm thick is unlikely to be laterally continuous unbroken unit capable of maintaining a stable lithic character over a sizeable area. Thus, seal continuity rather than measured seal capacity (e.g. entry pressure) becomes the most important factor in assessing seal quality.

Indeed, as noted by Warren (2007), average values of seal properties measured on discrete core samples are next to useless without a reliable geological model for the reservoir - what is needed is the knowledge of the likeliest weakest point in the seal across the structure of interest. A thicker seal provides many layers of contingent sealing beds and so gives a larger probability of a sealing surface being continuous over an entire target storage reservoir.

In hydrocarbon exploration, shale seals more than 50m thick and evaporate seals more than 10m thick are considered adequate for hydrocarbon trapping, while evaporate seals more than 30m thick are considered excellent (Warren, 2007).

CHAPTER 5:
HYDROCARBON TRAP



1 Introduction

Hydrocarbon traps form where permeable reservoir rocks (carbonates, sandstones) are covered by rocks with low permeability (caprocks) that are capable of preventing the hydrocarbons from further upward migration(**Figure 27**). Typical caprocks are compacted shales, evaporites, and tightly cemented sandstones and carbonate rocks. The caprock need not be 100% impermeable to water, oil or gas. If the upward loss of hydrocarbons is less than the supply of hydrocarbons from the source rocks to the trap, hydrocarbons may still accumulate.

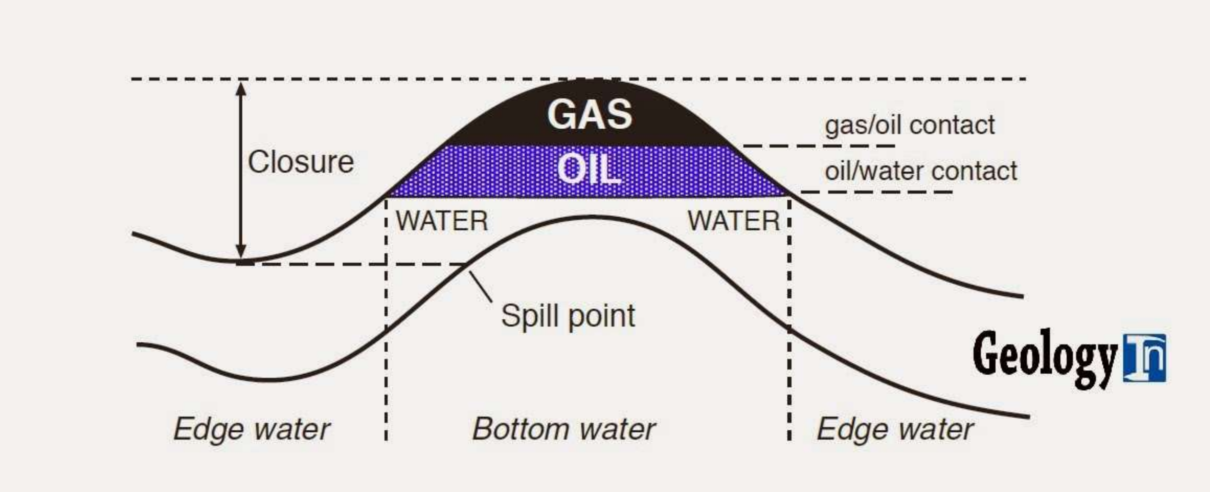


Figure 27. Simple anticlinal fold trap(https://wiki.aapg.org/Reservoir)

2 Basic Trap-Fluid Nomenclature:

Traps are usually classified according to the mechanism that produces the hydrocarbon accumulation(**Figure 28**). The two main groups of traps are those that are formed by structural deformation of rocks (structural traps), and those that are related to depositional or diagenetic features in the sedimentary sequence (stratigraphic traps). Many traps result from both of these factors (strati-structural or combination traps). A common example is stratigraphic pinch-out (e.g., a sandstone lens wedging into mudstone) that is combined with tectonic tilting (which allows hydrocarbons to pond in the updip part of the sandstone wedge).

Other traps result mainly from fracturing (which creates the reservoir porosity) or hydrodynamic processes.

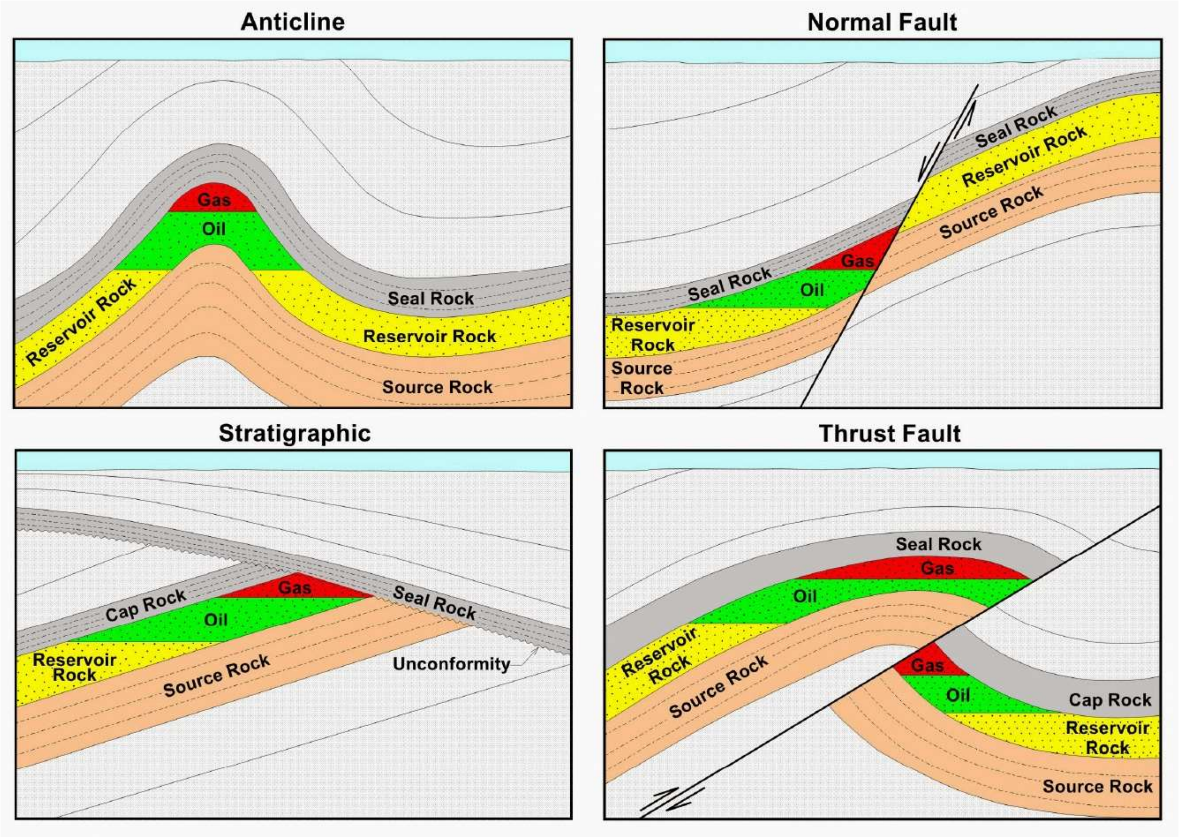


Figure 28. Simplified cartoons showing some common types of hydrocarbon traps recognized in producing oil and gas fields around the world (https://wiki.aapg.org/Reservoir)

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2.1 *Simple fold traps (anticlinal):* with axial culmination (fold axis dipping in two or more directions). The simplest type of trap is formed when a sandstone bed that is overlain by tight (i.e. low permeability) shale is folded into an anticline. A simple anticline, however, may not necessarily be a trap. The crest of the anticline must have an apical culmination (i.e. a peak) somewhere along the fold axis so that hydrocarbons can be trapped. Anticlinal traps are commonly detected by seismic reflection. In mature oilfields, most of these simple traps have probably been found, but many anticlinal traps remain to be discovered offshore and in new prospective areas.

2.2 *Fault traps:*The fault plane must have a sealing effect so that it functions as a fluid migration barrier for reservoir rocks. There are several common types of fault trap:

2.2.1 *Normal faults:* commonly associated with graben (rift) structures.

2.2.2 *Strike-slip faults*: these may not be sealed due to incremental movements, but basement-controlled strike-slip faults commonly produce good anticlinal structures in overlying softer sediments.

2.2.3 *Thrust faults:*commonly associated with compressional tectonics (e.g., the Front Ranges in Alberta).

2.2.4 *Growth faults:* typically form in sediments that are deposited rapidly, especially at deltas. Faulting occurs during sedimentation (i.e. syn-depositionally), such that the equivalent strata on the downthrow side will be thicker than on the upthrow side.

N.B. Many petroleum fields are closely linked to faulting, but traps that result from faulting alone are less common.

There are three common fault – petroleum pool associations:

- The fault itself makes the trap without an ancillary trapping mechanism such as a fold —normal faults are the most common examples.

- The fault creates another structure (e.g., a fold or horst) that in turn forms the main trap.

- The fault may be a consequence of another structure that forms the main trap — e.g., the extensional crestal faults that form above some anticlines.

2.3 *Salt Dome:*Salt domes form when salt is less dense than the overlying rock, and the salt moves slowly upwards due to its buoyancy**(Figure 29)**. For this to happen, there must be a minimum overburden and the thickness of the salt deposits must be more than ~100 m. Upward movement of salt through the sedimentary strata, and associated deformation is termed halokinetics or salt tectonics. Movements may continue for several hundred million years.

Traps may form:

- in the strata overlying the salt dome,
- in the top of the salt domes (the cap rock - caused by brecciation and dissolution),
- in the strata that curve upward against the salt intrusion
- due to stratigraphic pinch-out of strata around the salt dome

Salt dome reservoirs produce major oilfields where basial sediments contain thick salt deposits. Salt deposits are common in Permian-Jurassic sediments around the Atlantic Ocean. Examples include the Gulf of Mexico, where there is Permian and Jurassic salt, the Permian Zechstein salt in NW Europe and the North Sea.

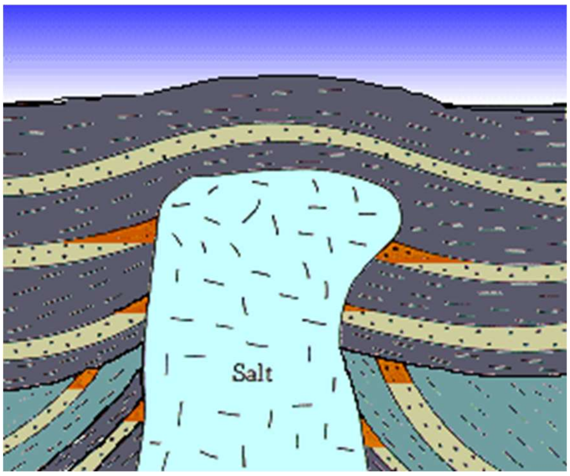


Figure 29. Salt dome trap(https://wiki.aapg.org/Reservoir)

2.4 *Stratigraphic Traps:*Stratigraphic traps are created by any variation in the stratigraphy that is independent of structural deformation, although many stratigraphic traps involve a tectonic component such as tilting of strata. Two main groups can be recognized**(Figure 30)**:

2.4.1 *Primary stratigraphic traps:* result from variations in facies that developed during sedimentation. These include features such as lenses, pinch-outs, and appropriate facies changes.

2.4.2 *Secondary stratigraphictraps:*result from variations that developed after sedimentation, mainly because of diagenesis. These include variations due to porosity enhancement by dissolution or loss by cementation.

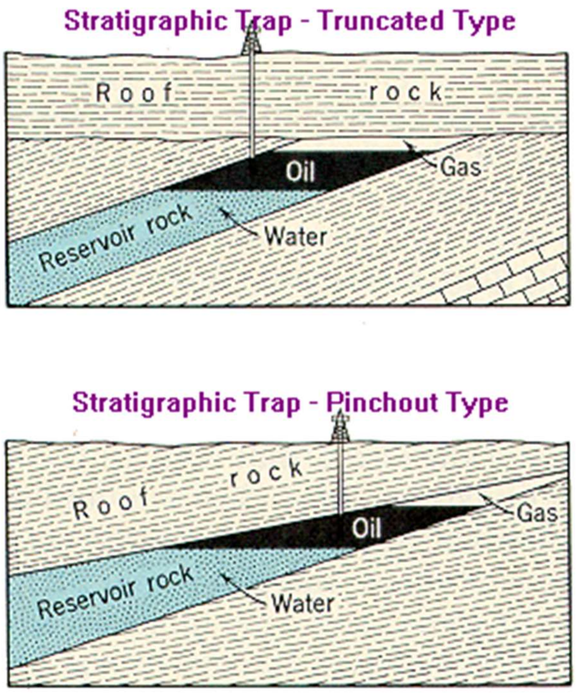


Figure 30. Stratigraphic traps: Truncated & pinchout types(https://wiki.aapg.org/Reservoir)

2.5 *Hydrodynamic Traps:*If porewater flow in a sedimentary basin is strong enough, the oil-water contact may deviate from the horizontal because of the hydrodynamic shear stress that is set up. In some cases, oil may accumulate without closure**(Figure 31)**. Flow of fresh (meteoric) water down through oil-bearing rocks commonly results in biodegradation of the oil and formation of asphalt, which may then form a cap rock for oil.

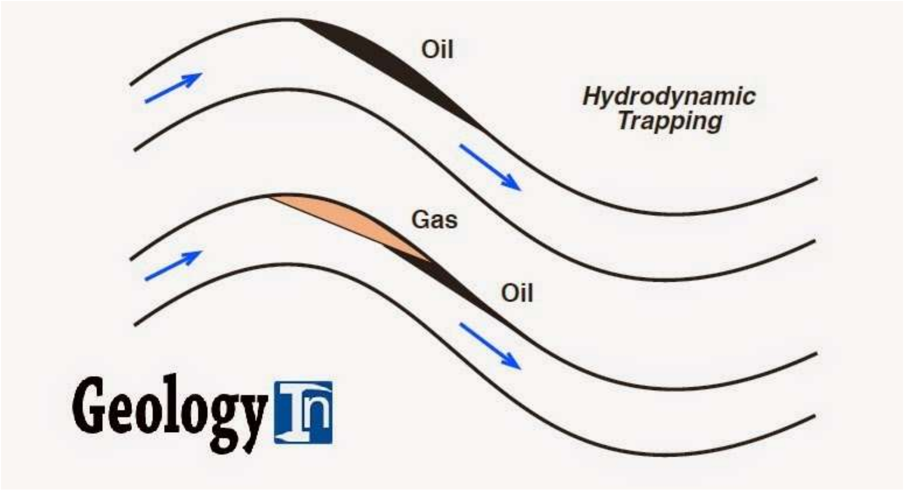
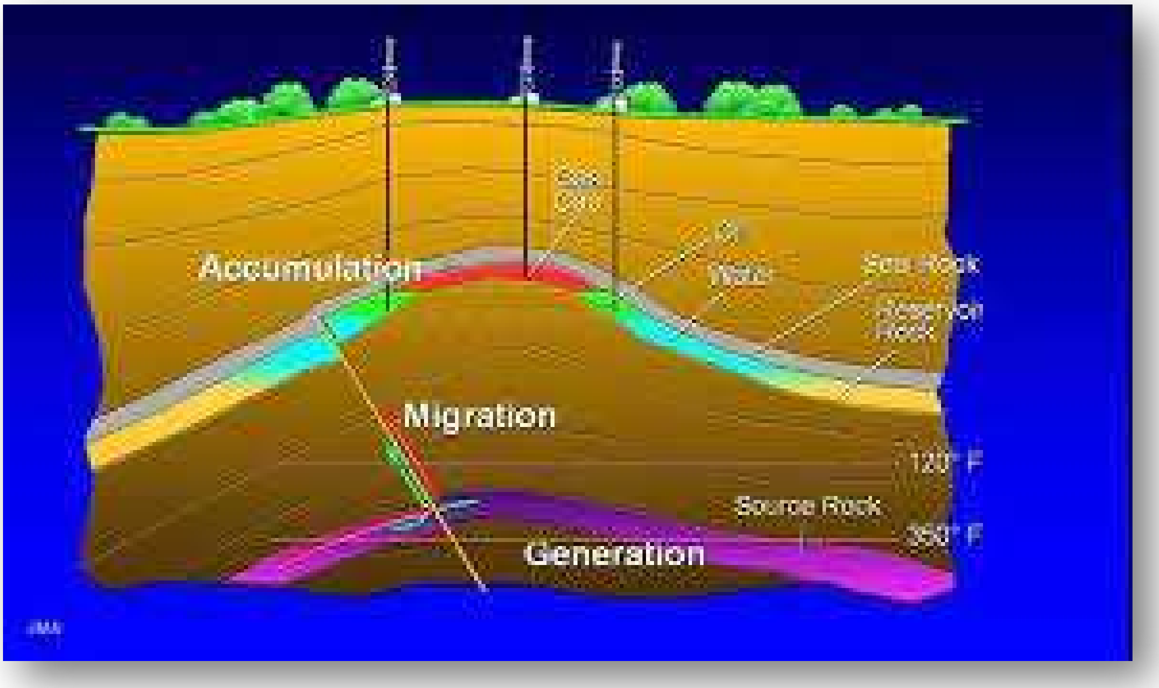


Figure 31. Hydrodynamic trap type(https://wiki.aapg.org/Reservoir)

CHAPTER 6 :

HYDROCARBON MIGRATION



1 Introduction

Migration is the movement of petroleum from source rock toward a reservoir or seep. Primary migration is expulsion of petroleum from fine-grained source rock, while secondary migration moves petroleum through a coarse-grained carrier bed or fault to a reservoir or seep**(Figure 32)**. Tertiary migration occurs when petroleum moves from one trap to another or to a seep. Hydrocarbon migration consists of four stages: primary, secondary, tertiary, and remigration.

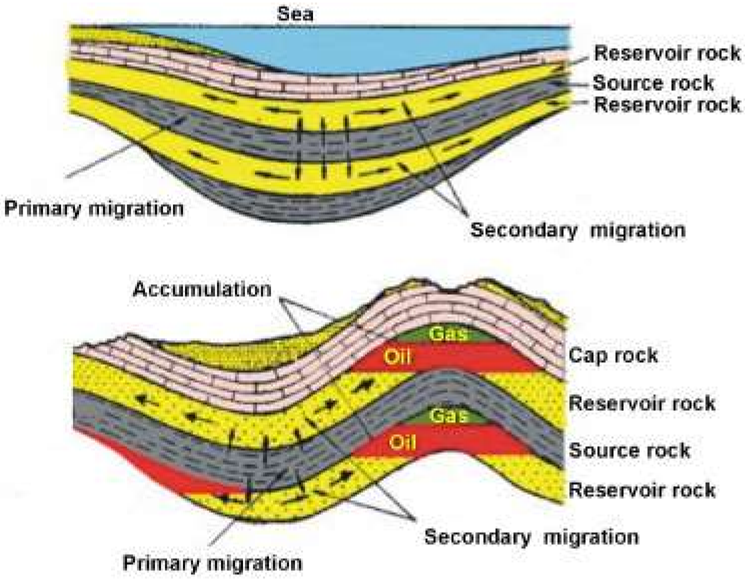


Figure 32. Primary and secondary migration pathways (Tissot and Welte 1984)

2 Principles of migration

2.1 *Separate phase:*primarily due to buoyancy. This force causes them to move vertically at geologically rapid rates

2.2 *Vertical movement:*Lithologic layers slow or restrict the vertical movement of hydrocarbons. Seals deflect the hydrocarbons laterally up dip through underlying beds to a trap or spill point. Lateral migration is also facilitated by meteoric groundwater flow. Flow rates for compaction-driven water generally are too slow to significantly affect hydrocarbon flow.

2.3 *The properties of reservoirs and carrier beds*: (dip, relative permeability, etc.) control the rate of migration and thus the specific direction of the bulk of hydrocarbons under seals.

3 Observations of migration

Hydrocarbon migration has been observed only rarely and indirectly in the natural environment under atypical conditions**(Figure 33)**. Observation is difficult because it occurs either too rapidly, too slowly, or elsewhere. As such, migration is generally inferred rather than demonstrated. Conclusions about migration are based on snapshots in reservoir and source-rock systems. Laboratory migration experiments are limited in their applications by the time frame and the ability to reproduce subsurface conditions.

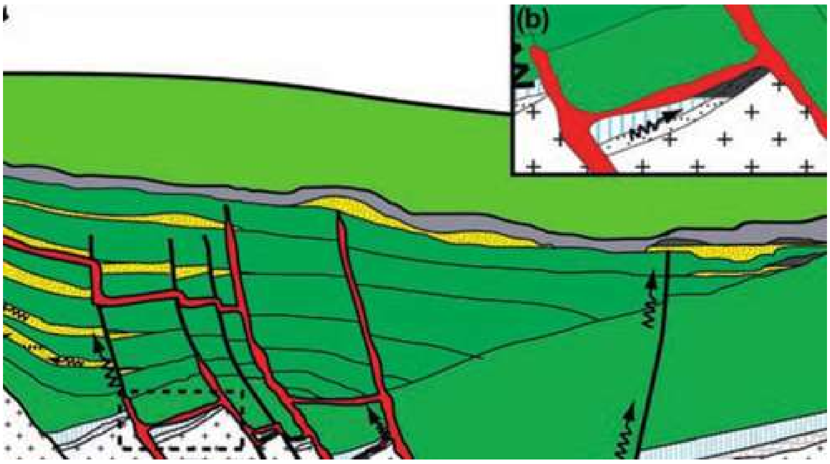


Figure 33. Hydrocarbon migration observation(Tissot and Welte 1984)

Physical conditions constraining migration through stratigraphic sections are pressure, temperature, permeability, capillarity, surface tension, molecular size, and density. The main chemical constraint is solubility of migrating hydrocarbons. Detailed chemical correlations made of reservoir hydrocarbons with source rocks strongly indicate that the migration process does not significantly affect the overall geochemistry of the migrated hydrocarbons. However, general differences exist between the chemical composition of oils and the source rocks to which they are chemically correlated. These differences must be explained.

Materials trapped in diagenetic overgrowths offer snapshots of the migration process. Studies of these materials by microanalytical techniques such as fluid inclusion analysis, micro-fluorescence, and cathodoluminescence offer potential for great advances in our understanding of the migration process and our ability to recognize and perhaps predict migration pathways and timing.

4 Migration stages

Hydrocarbon migration consists of four stages: primary, secondary, tertiary, and remigration**(Figure 34)**.

4.1 *Primary Migration:*The process of loss of hydrocarbons from the source rock.

4.2 *Secondary Migration:* Migration from source to reservoir along a simple or complex carrier system. Includes migration within the reservoir rock itself.

4.3 *Tertiary Migration:*Migration to the surface, either from a reservoir or source rock. Also called dismigration.

4.4 *Remigration:*Migration from one reservoir position through an intervening section into another reservoir position in the same or a different reservoir.

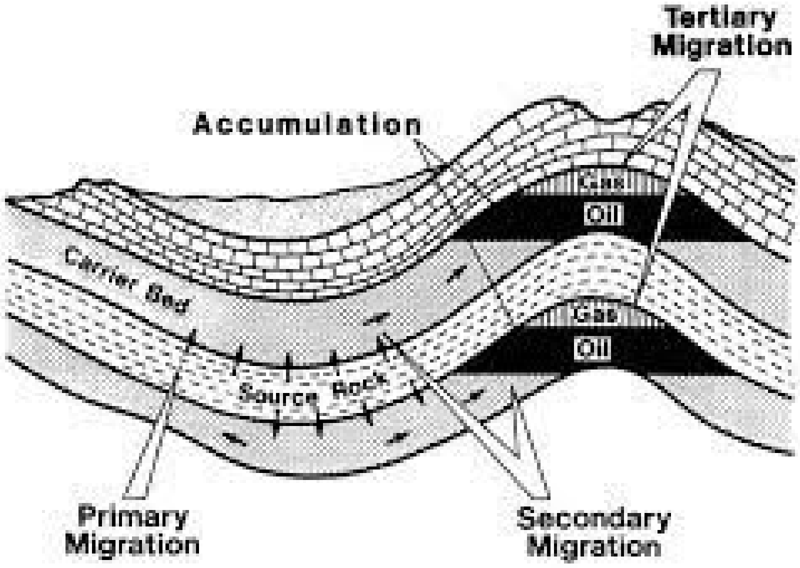
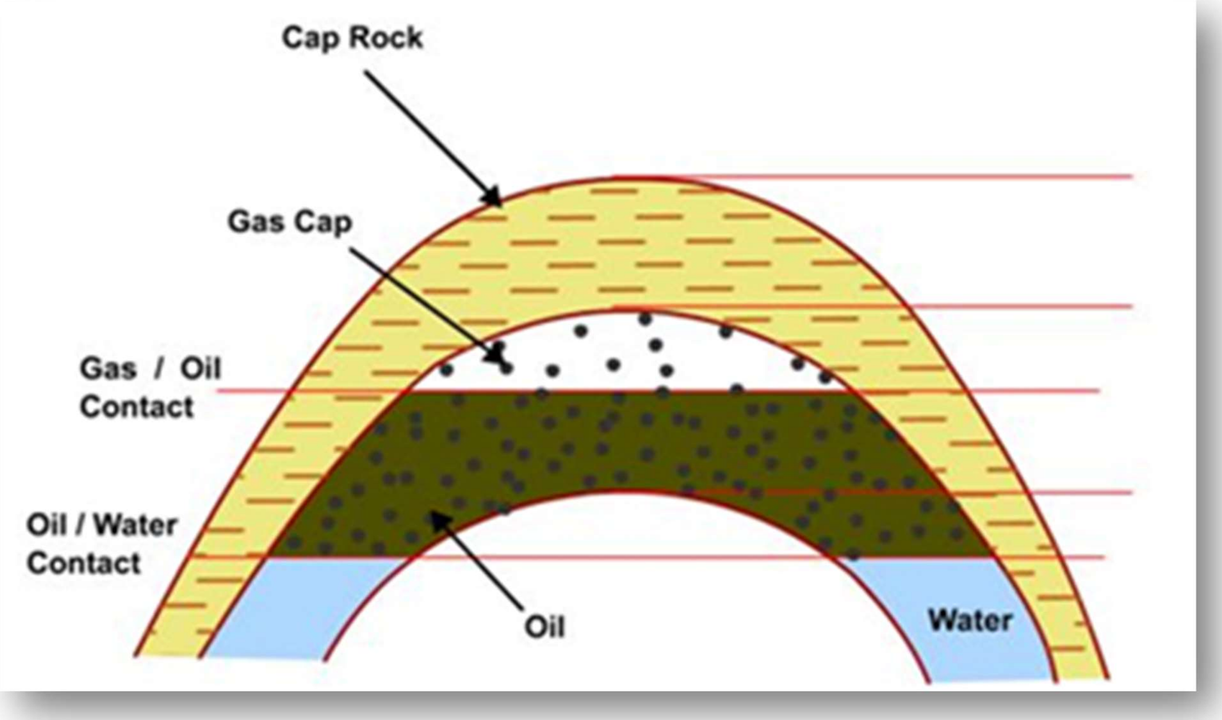


Figure 34. Hydrocarbon migration stages (Abu-Khamsin 2016)

CHAPTER 7 :

FLUID DISTRIBUTION WITHIN A RESERVOIR



1 Introduction

Petroleum reservoirs generally contain a combination of three fluids:

1). Natural Gas

2). Oil

3). Water

As hydrocarbons and water accumulate in a reservoir, vertical separation occurs as a result of the difference in the specific gravity of the various fluids. Typically, the lighter fluids, like gas, rise to the top of the reservoir. Below the lighter fluids is a gas to oil transition zone. This transition zone is a relatively thin zone above the oil accumulation. The oil accumulation may be of primary importance because it contains crude oil and possibly saturated gas. Below the oil accumulation in most reservoirs is an oil-water transition zone of varying thickness, which is partly filled with water and oil. Finally, beneath the oil-water transition zone is that part of the formation completely saturated with water. It is important to note that all reservoirs may not contain natural gas, oil, and water. Some formations may only contain water. However, any formation that contains hydrocarbons will also contain some amount of water. It is because of this water that we are able to measure the resistivity of a formation in logging.

2 The “Fluids First” Revolution:

Since the 1960’s, most developments in the logging industry have centered around the improvement of existing tools and new evaluation techniques. With the advent of Magnetic Resonance Imaging Logging (MRIL), the industry has been presented with an exciting method of evaluating hydrocarbon reservoirs. MRI logging had its beginnings in the late 1950’s and soon after was offered as a commercial service. With continued improvements in technology and analysis methods, MRIL is quickly becoming a high demand service. In 1997 Halliburton Energy Services acquired Numar Corporation, positioning itself as the industry leader in MRI logging. With time-honored logging tools such as the induction, resistivity, and neutron-density, there have always been limitations because of the effects of the formation upon log response**(Figure 35)**. These measurements depend upon petrophysical characteristics of the formation, whereas the main purpose of the logging industry is to investigate the fluids that these formations contain.

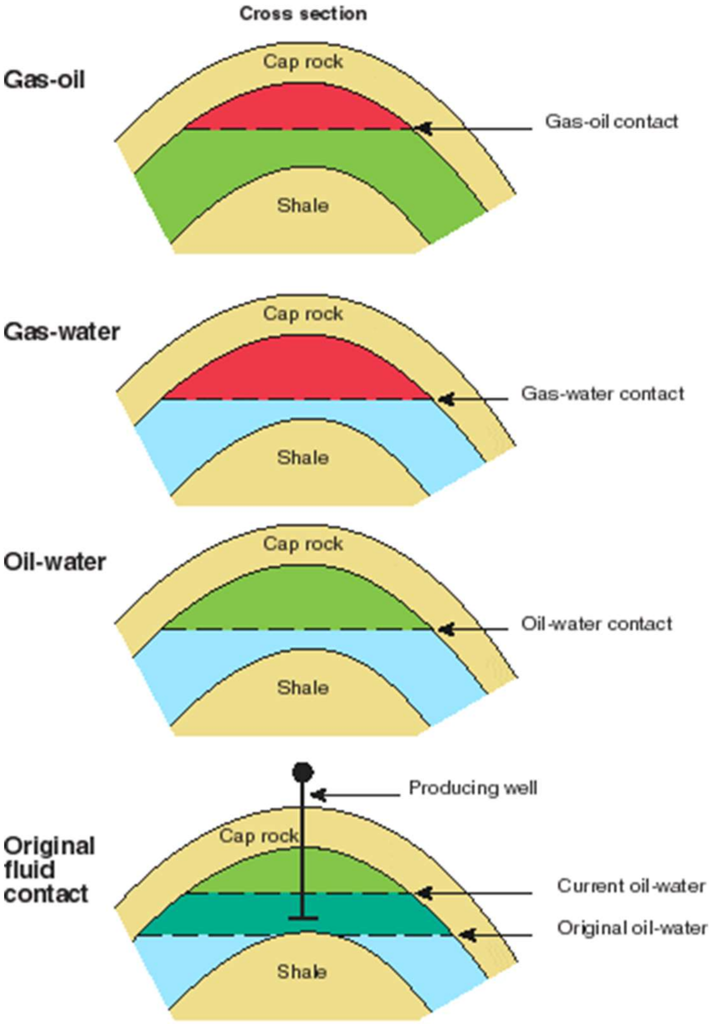


Figure 35.Schematic diagrams of various gas, oil and water contacts. (SLB Energy Glossary)

MRIL circumvents some of these problems by investigating “fluids first.” The measurement made by MRIL is not lithology-dependent, therefore it is a true measure of the fluids contained in a reservoir. Furthermore, the MRIL provides new measurements of effective porosity and clay bound porosity as well as links to reservoir permeability, fluid viscosity, and fluid type, which have been difficult to establish with conventional logging tools. An added benefit is that these measurements are made without nuclear sources. The “fluids first” revolution is refocusing the industry on the fluids of interest, and not necessarily the rocks that contain these fluids. Over the next few years, MRIL will no doubt become a very important component of any open hole logging job.

3 Reservoir Fluid Mechanics:

Reservoirs are composed of rock matrix, and pores and capillaries (channels between matrix grains that connect pores, sometimes called pore throats) of varying sizes. In sedimentary rocks, all of these pores are fluid saturated. The fluid is sometimes oil and/or gas, but water will always be present.

Most water found within the porosity of a reservoir is moderately saline. The degree of salinity is dependent upon the chemical history of that water. Formation water is commonly salty because of the fact that most sediments are deposited in marine environments. During deposition of these sediments, the salty formation water will become entrapped within the porosity. The salinity of this original formation water, however, may change with geologic time. Fresh water from the surface may infiltrate the sediments, mixing with the original salty formation water to form brackish water. In some instances, whether by osmosis or by fresh water being driven off from nearby formations, it is possible for salty formation water to be flushed from a formation altogether. The result may be a deep, fresh water-bearing formation. In some areas, fresh water is encountered at depths as great as 5,000 feet, but in others, salt water occurs at a depth of several hundred feet. The fluids in a sedimentary rock (whether water, oil, or gas) are constantly subjected to a variety of forces which include cohesion, surface tension, adhesion, interfacial tension, and capillary pressure. The interplay of these forces and their effect on the fluids and their movement is the subject of fluid mechanics. Basic to the understanding of fluid mechanics as it applies to hydrocarbon reservoirs is the concept of surface tension. All molecules in a fluid will attract each other mutually because of their force of cohesion. This can be demonstrated in **Figure 36**, which illustrates several molecules of water in a droplet of water. Molecule A will feel equally balanced forces of cohesion on all sides because of the surrounding water molecules. Molecule B, however, will feel no comparable attractive force from above. Consequently, there will be an unbalanced cohesive force at the air-water interface, which attempts to pull the molecules down and hold them together. This construer, squeezing against the water below and keeping the air-water interface straight. In a droplet of water, this same surface membrane keeps the droplet round, as if a balloon filled with liquid. Where one liquid is in contact with another liquid or is in contact with a solid, there exists an attractive force on both sides of their interface called adhesion. This attractive force is not balanced across the interface because the molecules on one side of the interface are completely different from those on the other. The tension resulting from such unbalanced attractive forces between two liquids or between a liquid and a solid is called interfacial tension. Interfacial tension accounts for whether a fluid will be adhered to the surface of a solid or repelled from that surface-active force is called surface tension. The top layer of molecules acts much like a membrane of Water,for example, will spread out and adhere to glass because its interfacial tension is low in comparison to that of glass. Mercury, on the other hand, has an interfacial tension that is high compared to that of glass and therefore will not adhere to the glass, but rather contract into a droplet. This principle is extremely important in reservoir fluid mechanics because these same forces operate between rock material (matrix) and the fluids filling the porosity. The force of adhesion between water and most matrix material is greater than that of most oils. Therefore, if a rock contains both water and oil, typically the water will occur as a film adhering to the rock grains with the oil occupying the space between (**Figure 37**). Such a reservoir is said to be water-wet, because water is the fluid phase that is “wetting” the grains of the rock. In some instances, although rarer, the chemistry of the oil may be such that it is the fluid that is in contact with the grains of the rock. This type of reservoir is said to be oil-wet.

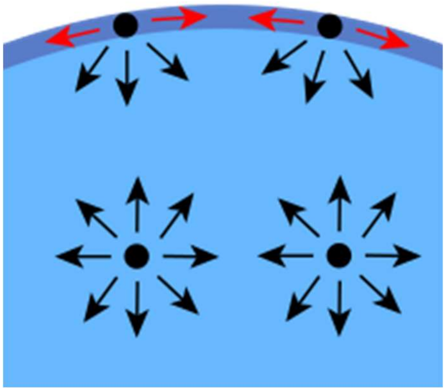


Figure 36.Diagram of the cohesive forces on molecules of a liquid (WIKIPEDIA)

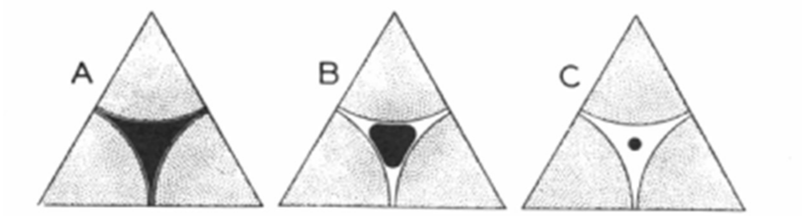


Figure 37.Non wetting oil (black) and water (blank) in a single water-wet pore

4 Capillary Pressure :

Reservoir rocks are composed of varying sizes of grains, pores, and capillaries (channels between grains which connect pores together, sometimes called pore throats). As the size of the pores and channels decrease, the surface tension of fluids in the rock increases. When there are When there are several fluids in the rock, each fluid has a different surface tension and adhesion that causes a pressure variation between those fluids. This pressure is called capillary pressure and is often sufficient to prevent the flow of one fluid in the presence of another. For example, **Figure 38** shows that the same adhesive forces that were mentioned previously will cause water, when in contact with air, to rise slightly against the walls of its container, against the pull of gravity, and form a concave meniscus. If several tubes of varying diameter are placed in a water-filled container, a meniscus forms on the inside walls of the tubes. In the very narrow tubes, the entire air-water interface will be concave upward. However, surface tension at the air-water interface will attempt to flatten this interface, thereby causing a slight rise in the level of water across the entire diameter of the tube. As this occurs, the adhesion of the water to glass will continue to pull water molecules upward near the edge of the tubes. By this mechanism the water level in the tube will continue to rise until the upward force is balanced by the weight of the water column. Again, referring to **Figure 38**above, the strength of the capillary pressure may be thought of in terms of the concavity of the air-water interfaces seen in the different tubes. The greater the capillary pressure, the more the air-water interface will be distorted into concavity by the adhesionof water to glass on the side of the tube. As seen in the illustration, the air-water interfaces in the narrow tubes exhibit more concavity than to the air-water interfaces in the wide tubes. Consequently, the height of the water columns in the B tubes (which are narrow) rise even higher than that of the A tubes (which are wider). The smaller the opening, the greater the capillary pressure. With respect to a reservoir, this may be thought of in terms of pore throat diameters.

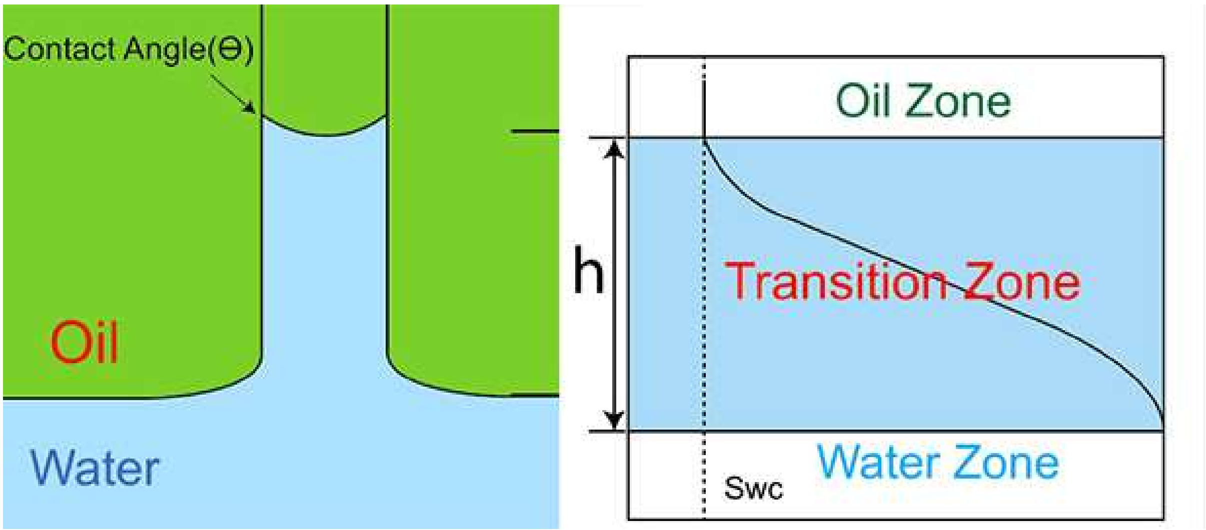


Figure 38.Capillary Diagram(Abu-Khamsin 2016)

5 Small pore throat diameters:

Generally, yield higher capillary pressures because of the greater amount of surface tension. Small pores that are often associated with small pore throat diameters will have a high-surfaceto-volume ratio, and therefore may contain greater amounts of adsorbed (adhered) water**(Figure 39)**.

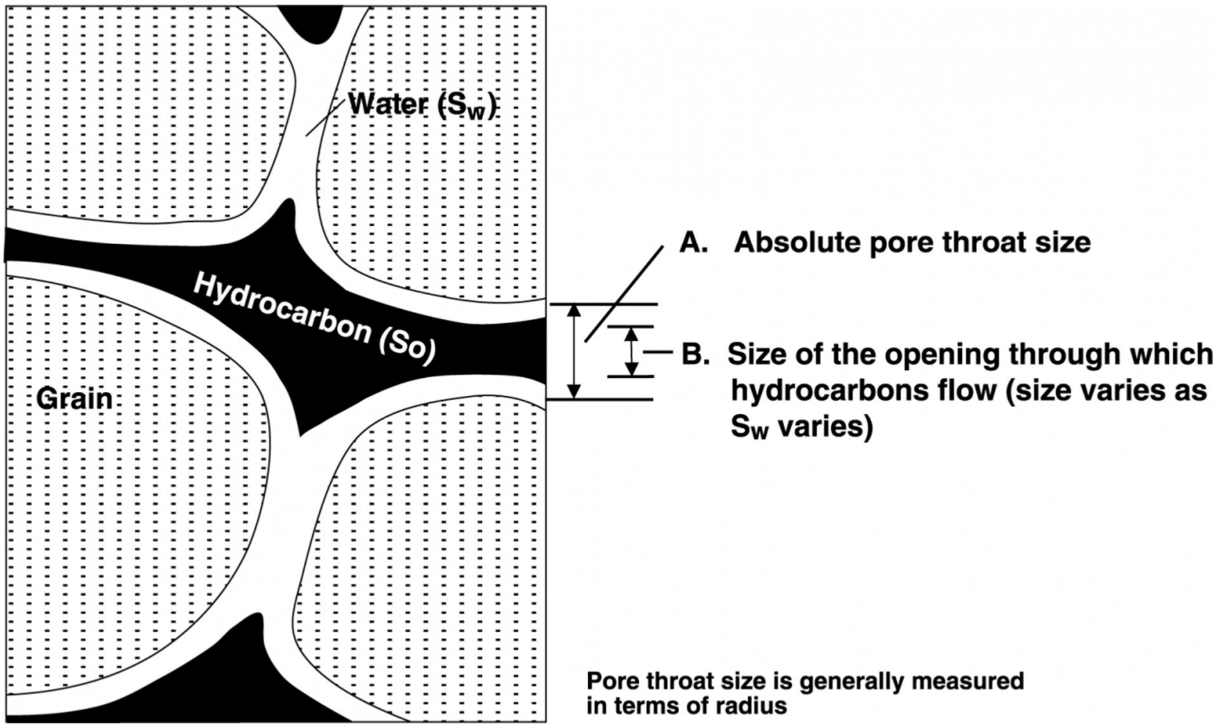


Figure 39.Grain size effects on capillary pressure and pore throat diameters(Abu-Khamsin 2016)

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