



قسم الجيولوجيا



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Petroleum Geology

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1. Introduction.

Petroleum is rock oils from the Latin “Petra” rock or stone and “oleum” means oil. It is a mineral substance composed of hydrocarbons (oil and natural gas) and produced from the natural accumulations of organic matter of a faunal and/or floral provenance (algae, plankton and other microscopic fauna). This process forms hydrocarbons (compounds of hydrogen and carbon) with small amounts of sulphur, nitrogen and hydrogen, which are powerful combustible fuels. Petroleum is a gaseous, liquid or semisolid substance, present in the pore space of porous rocks, referred to as reservoir rocks, which are mainly of sedimentary origin.

Petroleum geology is the study of origin, occurrence, movement, accumulation, and exploration of hydrocarbon fuels. It refers to the specific set of geological disciplines that are applied to the search for hydrocarbons (oil exploration).

History

In some places, for example, Germany in the 1800s, small mines were dug to get at the oil. Before 1859 oil was also recovered from coal for use in kerosene lamps. It was not until Edwin Drake’s exploits in 1859 at Oil Creek near Titusville in western Pennsylvania that oil was recovered in any quantity from boreholes. He drilled a well about 25 m deep which produced 8–10 bbl /day, a huge production rate compared with anything earlier.

A few years later there were 74 wells round Oil Creek, and the USA’s annual production had risen to half a million barrels. In southern California oil production started early in 1864 (in Santa Paula), but for many years oil was mined by driving shafts into the oil-bearing strata because it was so heavy and biodegraded that it would not flow in a well.

Oil production developed rapidly up to the end of the nineteenth century, and more systematic geological principles for prospecting were gradually developed. Since the 1970s an increasingly large share of international prospecting has taken place offshore,

helped by improved seismic methods. Advanced well log technology, in particular, made it possible to gain optimal information from each well.

Chemical composition

The petroleum is an extremely complex mixture of hydrocarbon compounds with a minor amount of nitrogen, oxygen and sulphur as impurities. Liquid hydrocarbon is termed as crude oil. Hydrocarbon gas commonly called natural gas (lighter paraffin hydrocarbons).

Petroleum is composed of four main hydrocarbon fractions:

- Saturated hydrocarbons: a) Normal alkanes (normal Paraffins), b) Branched alkanes (branched Paraffins), and c) Cycloalkanes (cycloparaffins).
- Unsaturated hydrocarbons: a) Simple aromatics, b) Naphththenoaromatics, and c) Small sulfur-bearing compounds.
- Resins (NSO's polar) : a) Porphyrins and b) Fatty acids

Petroleum industry

As a result, the petroleum industry is now a major component of the global economy. Most petroleum products derived from refining crude oil are combusted to provide energy as in diesel fuel, jet fuel, kerosene, fuel oil and gasoline. The burning of fossil fuels (coal, natural gas and oil) provides the vast majority of energy today and the dependence on petroleum products is anticipated to continue into the foreseeable future. However, there are a number of environmental concerns associated with the burning of petroleum products. Natural gas, or methane, has many uses including home heating and cooking, electrical power generation plants, and as a feedstock for certain chemical processes. In addition to producing refined fuels, crude oil can also provide petrochemicals for a wide range of uses, both as products themselves and as chemical feedstocks used to make other products. These petrochemical products include pharmaceuticals, plastics, synthetic rubbers, insecticides, fungicides, fertilizers, and lubricants.

There are seven major conceptual steps involved in the complete commercial “Petroleum Product Life Cycle”. These steps are: 1) Prospecting, 2) Leasing or acquiring access, 3) Drilling operations, 4) Developing and producing, 5) Transporting, 6) Processing and refining and 7) Marketing and sales. Of the seven steps listed above, the first three steps are called the “exploration phase” and the fourth step is the “production/extraction phase”. The majority of wildcat wells drilled to date have been dry holes that contained no commercial hydrocarbons.

2. Petroleum system.

Petroleum system is a core concept of petroleum geology. Geologic components and processes necessary to generate and store hydrocarbons. The petroleum systems, including all processes from source rocks deposition to final entrapment of hydrocarbons. Studying the petroleum system helps petroleum geophysicists and geochemists knowing and understanding the nature of the trap and petroleum region by basing on palaeontology, stratigraphy and sedimentology of a geographic region in order to identify petroleum system. The elements of the petroleum system include:

1. Source rock
2. Maturation
3. Migration pathway
4. Reservoir rock
5. Seal or cap rock
6. Trap

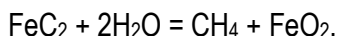
Appropriate relative timing of formation of these elements and the processes of generation, migration, and accumulation are necessary for hydrocarbons to accumulate and be preserved.

2.1 Oil generation and Source rock

Where does petroleum come from?. The precise details regarding the origin of the petroleum have yet to be fully answered. The composition of petroleum contains molecular signals which allow unrevealing their origin and geological history. As a general rule, the origin of petroleum is never in the reservoir accumulation from which it is produced. Instead, petroleum has experienced a long series of processes prior to accumulation in the reservoir. There are two theories of origin: Organic (bionic) or Inorganic (abionic).

2.1.1 Inorganic hypothesis

Early theories postulated an inorganic origin when it became apparent that there were widespread deposits of petroleum throughout the world. Dmitri Mendele'ev (1877), a Russian and the father of the periodic table of elements, reasoned that metallic carbides deep within Earth reacted with water at high temperatures to form acetylene (C₂H₂) which subsequently condensed to form heavier hydrocarbons. This reaction is readily reproduced in the laboratory. Other hypotheses (Berthelot, 1860, Mendele'ev, 1902) were a modification of the acetylene theory. They theorized that the mantle contained iron carbide which would react with percolating water to form methane:



The problem was and still is the lack of evidence for the existence of iron carbide in the mantle. These theories are referred to as the deep-seated terrestrial hypothesis.

Another inorganic hypothesis was suggested by Sokoloff (1890) who proposed a cosmic origin. His theory was one of hydrocarbons precipitated as rain from original nebular matter from which the solar system was formed and then ejected from earth's interior onto surface rocks. This theory and others like it are referred to as the extraterrestrial hypothesis.

20th Century variants and a renewed interest to the inorganic mode of origin by others was caused by two discoveries: Existence of carbonaceous chondrites (meteorites) and the discovery that atmospheres containing methane exists for some celestial bodies such as Saturn, Titan, Jupiter. The only known source for methane is through inorganic reactions. It has been postulated that the original atmosphere of earth contained methane, ammonia, hydrogen, water vapor; add to this photochemical reactions (due to UV radiation) and the result is the creation of an oily, waxy surface layer that may have been host to a variety of developing prebiotic compounds including the precursors of life.

The discovery (Mueller, 1963) of a type of meteorite called carbonaceous chondrites, also led to a renewed interest in an inorganic mechanism for creating organic compounds. Chondritic meteorites contain greater than 6% organic matter (not graphite) and traces of various hydrocarbons including amino acids. The chief support of an inorganic origin is that the hydrocarbons methane, ethane, acetylene, and benzene have repeatedly been made from inorganic sources. For example, congealed magma has been found on the Kola Peninsula in Russia (Petersil'ye, 1962) containing gaseous and liquid hydrocarbons (90% methane, traces of ethane, propane, isobutane). Paraffinic hydrocarbons have also been found in other igneous rocks (Evans, Morton, and Cooper, 1964).

There are problems however, with the inorganic hypotheses. First, there is no direct evidence that will show whether the source of the organic material in the chondritic meteorites is the result of a truly inorganic origin or was in an original parent material which was organically created. Similar reasoning applies to other celestial bodies. Second, there is no field evidence that inorganic processes have occurred in nature, yet there is mounting evidence for an organic origin. And third, there should be large amounts of hydrocarbons emitted from volcanoes, congealed magma, and other igneous rocks if an inorganic origin is the primary methodology for the creation of hydrocarbons. Gaseous hydrocarbons have been recorded (White and Waring, 1963) emanating from volcanoes, with methane (CH₄) the most common. Volumes are

generally less than 1%, but as high as 15% have been recorded. But the large pools are absent from igneous rocks. Where commercial accumulations do occur, they are in igneous rocks that have intruded into or are overlain by sedimentary materials; in other words, the hydrocarbons probably formed in the sedimentary sequence and migrated into the igneous material.

Conclusion: There are unquestioned instances of indigenous magmatic oil. But the occurrences are rare and the volumes of accumulated oil (pools) are infinitesimally low. Other problematic issues: Commercial accumulations are restricted to sedimentary basins, and gas chromatography can fingerprint the organic matter in shales to that found in the adjacent pool. The occasional occurrence of oil and gas fields hosted in fractured basement rocks (e.g. granites, basalts, and metamorphic rocks). In most of these cases, it could be demonstrated that the petroleum materials were ultimately generated in sedimentary rocks and had been migrated over long distances to accumulate in fractured basement rocks. These cases of petroleum occurring in basement rocks are extremely rare and not commercially important when compared to the vast majority of hydrocarbon reserves in sedimentary basins. Thus current theory holds that most petroleum is formed by the thermal maturation of organic matter - An Organic Origin generated the vast reserves (pools) of oil and gas.

2.1.2 Organic hypothesis

There are a number of compelling reasons that support an organic development hypothesis. First and foremost, is the carbon-hydrogen-organic matter connection. Carbon and Hydrogen are the primary constituents of organic material, both plant and animal. Moreover, carbon, hydrogen, and hydrocarbons are continually produced by the life processes of plants and animals. A major breakthrough occurred when it was discovered that hydrocarbons and related compounds occur in many living organisms and that these same hydrocarbons are deposited in the sediments with little or no change.

Second were observations dealing with the chemical characteristics of petroleum reservoirs. Nitrogen and porphyrins (chlorophyll derivatives in plants, blood derivatives in animals) are found in all organic matter; they are also found in many petroleums. The highly specific carbon structures of these molecules (porphyrins) could not be synthesized by inorganic reactions. They are clearly and uniquely derived from molecular structures synthesized by living organisms. Presence of porphyrins also mean that anaerobic conditions must have developed early in the formation process because porphyrins are easily and rapidly oxidized and decompose under aerobic conditions. Additionally, low Oxygen content also implies a reducing environment. Thus there is a high probability that petroleum originates within an anaerobic and reducing environment.

Third were observations dealing with the physical characteristics. Nearly all petroleum occurs in sediments that are primarily of marine origin. Petroleum contained in non-marine sediments probably migrated into these areas from marine source materials located nearby. Furthermore, temperatures in the deeper petroleum reservoirs seldom exceed 300°F (141°C). But temperatures never exceeded 392°F (200°C) where porphyrins are present because they are destroyed above this temperature. Therefore the origin of petroleum is most likely a low-temperature phenomenon.

Evidences supporting the organic origin of petroleum:

- a. Optical conductivity: It is the ability of crude oil to move the polarized light. This makes oil in the group of organic matter which only limited for these substances.
- b. Including the oil symmetrical groups of structure from hydrocarbons containing large numbers of a single pattern. It is very important to mention that compounds of organic origin are different to be from through in-organic methods. This reflects an important actual argument on the possibility of formation of petroleum from inorganic processes.

- c. Presence of petroleum in most cases in marine sedimentary rocks, except few cases it occurs in non-sedimentary rocks (e.g. igneous, metamorphic) which many support that oil moves from origin sites to these rocks through fractures (e.g. faults).
- d. Presence of petroleum in relative rocks and presence in little amounts in rocks of ancient ages. This refutes the origin of oil as a result of chemical reactions in the interior of the earth.
- e. Presence of porphyrin which is the product of natural organic processes.
- f. Presence of Vanadium (V) and Nickel (Ni) which are found in organic materials.
- g. Presence of Nitrogen (N₂) and its products.

Organic Hypothesis - Summary. The organic theory became the accepted theory about the turn of the century as the oil and gas industry began to fully develop and geologists were exploring for new deposits. Simply stated, the organic theory holds that the carbon and hydrogen necessary for the formation of oil and gas were derived from early marine life forms living on the Earth during the geologic past - primarily marine plankton. Although plankton are microscopic, the ocean contains so many of them that over 95% of living matter in the ocean is plankton. The Sun's energy provides energy for all living things including plankton and other forms of marine life (Fig.1). As these early life forms died, their remains were captured by the processes of erosion and sedimentation (Fig 2). Successive layers of organic-rich mud and silt covered preceding layers of organic rich sediments and over time created layers on the sea floor rich in the fossil remains of previous life (Fig. 3). Thermal maturation processes (decay, heat, pressure) slowly converted the organic matter into oil and gas. Add additional geologic time (millions of years) and the organic rich sediments were converted into layers of rocks. Add more geologic time and the layers were deformed, buckled, broken, and uplifted; the liquid petroleum flowed upward through porous rock until it became trapped and could flow no further forming the oil and gas that we explore for at present (Fig. 4). But the chemistry of the hydrocarbons found in the end product (oil, gas) differ somewhat from those we

find in living things. Thus changes, transformation, takes place between the deposition of the organic remains and the creation of the end product.

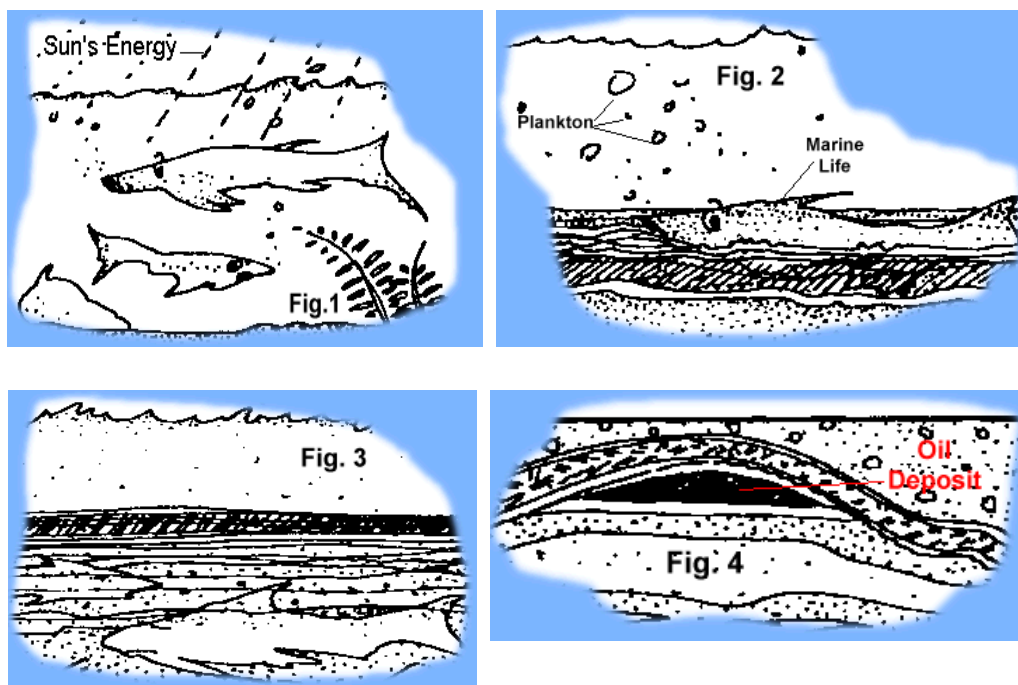


Fig. 1, 2, 3, and 4 for organic hypothesis.

2.1.3 Source rocks

We have spent some time on the two major hypotheses of the origin of petroleum. In this section we will look at the raw material that eventually ends up as "petroleum." On other pages we will look at how petroleum gets from one place to another (migration) and then forms into large pools (accumulation).

Source rocks are a rock rich in primary organic matter and have the capability to generate sufficient quantities of hydrocarbons. The ability of a rock to generate and expel hydrocarbons is dependent on the quantity of organic matter present. They form one of the necessary elements of a working petroleum system. They are organic-rich sediments that may have been deposited in a variety of environments including

deepwater marine, Lacustrine and deltaic (low energy, anoxic marine). Usually, this is shale or mudrock (containing abundant plankton) which itself is a very common rock type, consisting about 80% of the world's sedimentary rock volume. Organic carbon-rich shale and mudrock are characteristically black or dark greyish in color, which indicates a non-oxidized primary organic matter (Fig. 5 and 6). Oil shale can be regarded as an organic-rich but immature source rock from which little or no oil has been generated and expelled. Local large concentrations of organic matter in sedimentary rocks, in the form of coal, oil or natural gas are called fossil fuels.

Fig. 5: Kimmeridge clay Formation (Northwest European sedimentary basins), source rock where as much as 25% of the world's conventional hydrocarbons.



Fig. 6: Woodford shale (Oklahoma)



Just a source rock is present, and then you ask, how good is it? Will it generate oil or gas? Has it generated hydrocarbon already?. To answer these questions, you must

know the basics of what constitutes a source rock. A petroleum source rock is characterized three features:

1. Must have a sufficient quantity of organic matter, this organic matter must be of a specific composition, i.e. hydrogen-rich.
2. Quality capable of yielding moveable hydrocarbons.
3. Thermal maturity.

The first two components are products of the depositional setting, and the third is a function of the structural and tectonic history of the province. Source rocks can be divided into at least four major categories; a) Potential, b) Effective, c) Relic effective and d) Spent (Table 1).

Table 1: Categories of source rock and their definitions

| Type | Definition |
|------------------------------|---|
| Potential source rock. | Rock which contains organic matter in sufficient quantity to generate and expel hydrocarbons if subject to increase thermal maturation. |
| Effective source rock. | Rock which contains organic matter and is presently generating and /or expelling hydrocarbons to form commercial accumulations. |
| Relic effective source rock. | An effective source rock which has ceased generating and /or expelling hydrocarbons due to a thermal cooling event such as uplift or erosion before exhausting its organic matter supply. |
| Spent source rock. | 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 over mature state. |

Organic matter

The primary source materials (organic matter) are fish and microscopic marine life. Some species of fish contain greater than 50% oil and there have been enough fish since Ordovician time to account for ALL known oil deposits in the world. Moreover, fossilized fish are common in sedimentary strata believed to be source rocks. But fish

are nektonic animals, they swim about. Upon death, they sink to the sea floor. The fossil record is full of fish accompanied with other benthonic organisms.

Microscopic marine life, plankton, are considered to be the primary source of all hydrocarbons. There are two types of plankton: Phytoplankton are the most important and comprise the bulk of the marine plankton. The most abundant volumetrically, are the Diatoms, siliceous unicellular plants. Diatoms contain minute droplets of oil that accumulate in their cellular structure late in the vegetative period. The other type of plankton is Zooplankton. Foraminifera and Radiolaria are the most widely represented fossils in young oil-bearing strata with Copepods being the most numerous. Modern zooplankton also contain minute oil droplets. The reason for the oil droplets is uncertain; they may be formed during the decay process of the animal, or be a food reserve, or may be developed early in their life cycle as a floating mechanism to reduce their density in water. Whatever the reason, the bulk of evidence favors planktonic aquatic organisms, zooplankton and phytoplankton, as the primary source material for the formation of oil and wet gas.

The major groups of chemicals that occur in organic matter are proteins, carbohydrates, lipids, and lignin. The proteins are found largely in animals and to a lesser extent in plants. They contain the elements hydrogen, carbon, oxygen, and nitrogen, with some sulfur and phosphorus. This combination of elements occurs in the form of amino acids. The carbohydrates are present in both animals and plants. They have the basic formula $C_n(H_2O)_n$ and include the sugars, such as glucose, and their polymers-cellulose, starch, and chitin. The lipids are also found in both animals and plants. They are basically recognized by their insolubility in water and include the fats, oils, and waxes. Chemically, the lipids contain carbon, hydrogen, and oxygen atoms. The basic molecule of the lipids is made up of five carbon atoms (C_5H_8). The last of the four major groups of organic compounds is lignin, which is found only in the higher plants. Lignin is a polyphenol of high molecular weight, consisting of various types of aromatic carbon rings. Table 2 shows their abundance in different groups of animals and plants.

Table 2: Chemical Composition of Various Groups of Animals and Plants.

| Substance | Weight percent of major constituents (ash-free) | | | |
|----------------------|---|---------------|--------|--------|
| | Proteins | Carbohydrates | Lignin | Lipids |
| Plants | | | | |
| Spruce | 1 | 66 | 29 | 4 |
| Oak leaves | 6 | 52 | 37 | 5 |
| Pine needles | 8 | 47 | 17 | 28 |
| Phytoplankton | 23 | 66 | 0 | 11 |
| Diatoms | 29 | 63 | 0 | 8 |
| Lycopodium spores | 8 | 42 | 0 | 50 |
| Animals | | | | |
| Zooplankton | 60 | 22 | 0 | 18 |
| Copepods | 65 | 25 | 0 | 10 |
| Higher invertebrates | 70 | 20 | 0 | 10 |

From: *Hunt (1979)*. Used with permission.

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 favored by a high rate of production of organic matter and a high preservation potential.

In the sea, as on the land, all organic matter is originally formed by photosynthesis. The photosynthesizers in the sea are pelagic phytoplankton and benthic algae. The biological productivity of these plants is related to both physical and chemical parameters. Of the former, temperature and light are of foremost significance. The amount of light is dependent on the depth, latitude, and turbidity of the water. The amount of organic productivity is the highest in the shallow photic zone and decreases rapidly with increasing water depth and decreasing light and temperature.

Chemical conditions favoring organic productivity include the abundance of phosphates and nitrates. These chemicals are essential for the growth of plants and animals. Oxygenation is not important for the phytoplankton themselves, but is vital for the existence of animals that later form links in the food chain. Because oxygen is a by-product of photosynthesis, phytoplankton increases the oxygen content of the sea. It is important to stress that the areas of high oceanic productivity are not necessarily the areas where organic matter is best preserved. The preservation of organic matter is favored by anaerobic bottom conditions and a rapid sedimentation rate.

Within this depositional setting, oxygen and energy levels are perhaps the most critical aspects controlling the concentration and preservation of organic matter in the sediment. Oxygen-depleted, or anoxic, sediments provide the best media for preserving organic matter. Low oxygen levels create a reducing environment that shelters organic material from oxidation while also restricting the activity of bottom feeders.

The quantity of organic matter is commonly assessed by a measure of Total Organic Carbon (TOC) contained in the rock. The organic carbon concentration is an approximate measure of the organic matter content of a rock. Organic matter is predominantly composed of organic carbon, but also contains minor amounts of hetero-elements (N, S, and O). The TOC content is a measure of the source rock potential and is measured with total pyrolysis. Table 3 shows how TOC (in weight percent) relates to the source rock quality.

Table 3: TOC (in weight percent) relates to the source rock quality.

| Quality | TOC (in Weight Percent, Wt. %) |
|----------------|---------------------------------------|
| Poor | 0.0 – 0.5 |
| Fair | 0.5 – 1.0 |
| Good | 1.0 – 2.0 |
| Very good | 2.0 – 4.0 |
| Excellent | > 4.0 |

2.2 Maturation

2.2.1 Formation of Kerogen

Having now discussed the generation and preservation of organic matter at the earth's surface, it is appropriate to consider what happens to this organic matter when buried in a steadily subsiding sedimentary basin. As time passes, burial depth increases, exposing the sediment to increased temperature and pressure. Tissot (1977) defined three major phases in the evolution of organic matter in response to burial:

1. Diagenesis: This phase occurs in the shallow subsurface at near normal temperatures and pressures. It includes both biogenic decay, aided by bacteria, and abiogenic reactions. Methane, carbon dioxide, and water are given off by the organic matter, leaving a complex hydrocarbon termed *kerogen*. The net result of the diagenesis of organic matter is the reduction of its oxygen content, leaving the hydrogen:carbon ratio largely unaltered.
2. Catagenesis: 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. Metagenesis: This third phase occurs at high temperatures and pressures verging on metamorphism. The last hydrocarbons, generally only methane, are expelled. The hydrogen: carbon ratio declines until only carbon is left in the form of graphite.

Kerogen: is the solid organic matter in source rocks which is insoluble in low-boiling organic solvents. Kerogen is partly formed by the accumulation of resistant macromolecular substances of biological origin such as cellular lipids, algae cell walls, membranes, cuticles, spores and pollen, etc.

2.2.2 Chemistry of Kerogen

kerogen is the term applied to disseminated organic matter in sediments that is insoluble in normal petroleum solvents, such as carbon bisulfide. This insolubility distinguishes it from bitumen. Chemically, kerogen consists of carbon, hydrogen, and oxygen, with minor amounts of nitrogen and sulfur. Three basic types of kerogen are generally recognizable. The differences are chemical and are related to the nature of the original organic matter. Because these three kerogen types generate different hydrocarbons their distinction and recognition are important. Table 4 shows the chemistry of kerogens.

Table 4: The chemistry of kerogens.

| | Weight percent | | | | | Ratios | | Petroleum type |
|------------------------------------|----------------|------|------|------|-----|--------|------|----------------|
| | C | H | O | N | S | H-C | O-C | |
| Type I Algal (7 samples) | 75.9 | 8.84 | 7.66 | 1.97 | 2.7 | 1.65 | 0.06 | Oil |
| Type II Liptinic (6 samples) | 77.8 | 6.8 | 10.5 | 2.15 | 2.7 | 1.28 | 0.1 | Oil and gas |
| Type III Humic (3 samples) | 82.6 | 4.6 | | 2.1 | 0.1 | 0.84 | 0.13 | Gas |

Weight percent data from Tissot and Welte (1978), ratios from Dow (1977). Reprinted with permission from Springer-Verlag.

- Type I kerogen is essentially algal in origin. It has a higher proportion of hydrogen relative to oxygen than the other types of kerogen have (H:O ratio is about 1.2-1.7). The H:C ratio is about 1.65 (Table 4). Lipids are the dominant compounds in this kerogen, with derivatives of oils, fats, and waxes.
- Type II, or liptinitic, kerogen is of intermediate composition. Like algal kerogen, it is rich in aliphatic compounds, and it has an H:C ratio of >1. The original organic matter of type II kerogen consisted of algal detritus, and also contained material derived from zooplankton and phytoplankton. The Kimmeridge clay of the North Sea and the Tannezuft shale (Silurian) of Algeria are of this type.
- Type III, or humic, kerogen has a much lower H:C ratio (<0.84). Chemically, it is low in aliphatic compounds, but rich in aromatic ones. Humic kerogen is produced from

the lignin of the higher woody plants, which grow on land. It is this humic material that, if buried as peat, undergoes diagenesis to coal. Type III kerogen tends to generate largely gas and little, if any, oil. Nonmarine basins were once thought to be gas prone because of an abundance of humic kerogen, whereas marine basins were thought to be oil provinces because of a higher proportion of algal kerogen.

This review of the three basic types of kerogen shows the importance of identifying the nature of the organic matter in a source rock so as to assess accurately its potential for generating hydrocarbons. A second important factor to consider is not only the quality of kerogen but also the quantity necessary to generate significant amounts of oil and gas suitable for commercial production.

2.2.3 Maturation of Kerogen

During the phase of catagenesis, kerogen matures and gives off oil and gas. Establishing the level of maturation of kerogen in the source rocks of an area subject to petroleum exploration is vital. When kerogen is immature, no petroleum has been generated; with increasing maturity, first oil and then gas are expelled; when the kerogen is overmature, neither oil nor gas remains. Fig. 7 shows the maturation paths for the different types of kerogen. The maturation of kerogen can be measured by several techniques. The rate of maturation may be dependent on temperature, time, and, possibly, pressure.

Oil and gas windows

A number of workers have documented an empirical correlation between temperature and petroleum generation. Significant oil generation occurs between 60 and 120°C, and significant gas generation between 120 and 225°C. Above 225°C, the kerogen is inert, having expelled all hydrocarbons; only carbon remains as graphite. The temperatures just cited are only approximate boundaries of the oil and gas windows. Fig. 8 describes the oil and gas windows.

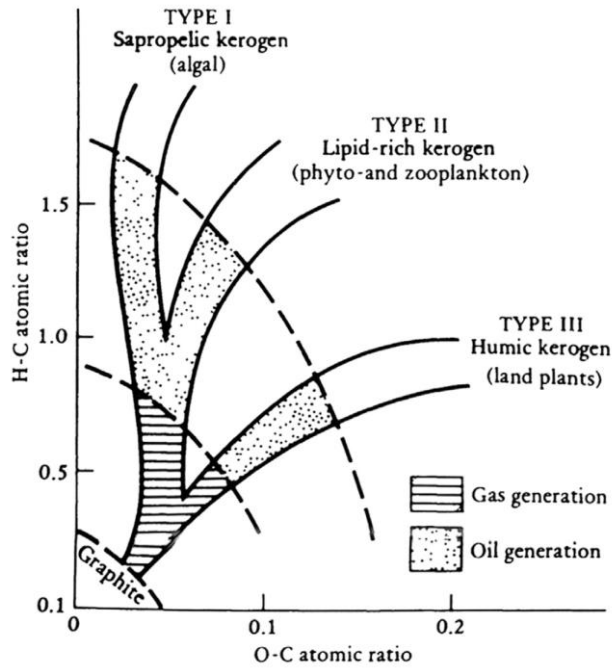


Fig. 7: Maturation paths of the three different types of kerogen.

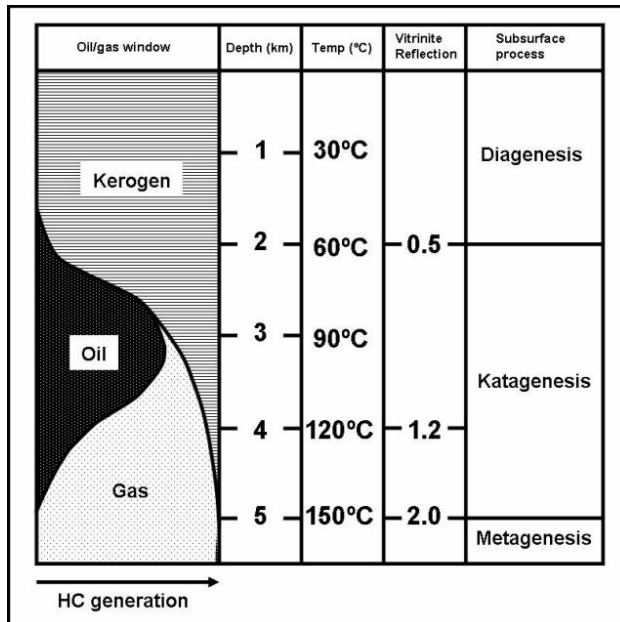


Fig. 8: Oil and gas windows

2.3 Oil Migration

The preceding sections showed that petroleum is of organic origin; discussed the production of organic matter and its preservation in sediments; and traced the diagenesis of organic matter into kerogen and the maturation of kerogen as petroleum is expelled. The object of this section is to discuss how fluid hydrocarbons may emigrate from the source rock to the reservoir. The oil migration is considered as an important stage in the history of oil lying between its origin stage and its accumulation.

A number of lines of observational evidence show that oil and gas do not generally originate in the rock in which they are found, but that they must have migrated into it from elsewhere. This theory is proved by the following observations:

1. As previously discussed, organic matter is easily destroyed by oxidization in porous, permeable sediments at the earth's surface. It must therefore have invaded the reservoir rock after considerable burial and raised temperature.
2. Oil and gas often occur in solution pores and fractures that must have formed after the burial and lithification of the host rock.
3. Oil and gas are trapped in the highest point (structural culmination, or stratigraphic pinchout) of a permeable rock unit, which implies upward and lateral migration.
4. Oil, gas, and water occur in porous, permeable reservoir rock stratified according to their relative densities. This stratification implies that they were, and are, free to migrate vertically and laterally within the reservoir.
5. Presence of oil seeps (petroleum seepage) is good evidence for the movement of the oil because the presence and occurrence of the oil on or near the ground surface should be emphasizes migration from deep reservoirs.
6. Accumulation of oil in igneous intrusive and metamorphic rock is good evidence for its migration from the source region to such rocks.

7. The several changes which influenced on the oil trap during its geological history should be changed from the oil position (location) in that trap until the oil reaches its gravity equilibrium with the changeable position of the trap.
8. Producing of oil and gas from pools identifies the ability of the oil to move through the permeable rock into the borehole.
9. Most of the petroleum deposits of great economic value are present in rocks have not any probability that contains source organisms (from which the oil had been formed). Therefore, the oil must be migrated from the source region into the reservoir.

2.3.1 Types of migration

An important distinction is made between primary and secondary migration (Fig. 9). Primary migration is understood as the emigration of hydrocarbons from the source rock (clay or shale) into permeable carrier beds (generally sands or limestones). Secondary migration refers to subsequent movement of oil and gas within permeable carrier beds and reservoirs. There is consensus that secondary migration occurs when petroleum is clearly identifiable as crude oil and gas, and, although gas may be dissolved in oil, their solubility in connate water is negligible. Secondary migration occurs by buoyancy due to the different densities of the respective fluids and in response to differential pressures.

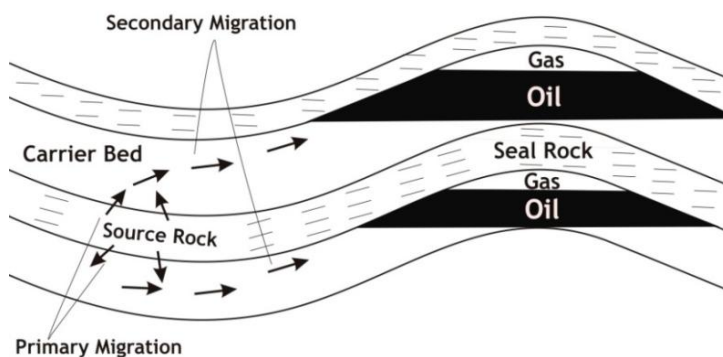


Fig. 9: Forms of petroleum migration.

1. Primary migration

Primary migration, the emigration of hydrocarbons from source bed to carrier, is still a matter for debate. The primary hydrocarbon migration, "which is the last great mystery of petroleum geology". Primary migration takes place within the source rock following its pressure fracturing. Thus, an important requirement for a productive source rock is that it be easily fractured. During primary migration, the gas and oil travel together as a single liquid phase due to the high pressures in the source rock.

Several geologists have suggested that fluid emigration from clays is aided by the development of microfractures. These microfractures would cause a marked increase in permeability and thus allow fluid to escape. The microfractures would then close as pore pressure dropped. Once the petroleum migrates out of the source rock, pressures decline, especially if the migration is vertical. Fluids tend to move toward the lowest potential energy. Initially, this is upwards, but as compaction progresses; there is lateral as well as vertical movement.

The study of primary migration contains a major paradox. Oil and gas are trapped in porous, permeable reservoirs. The source rocks from which they emigrated can be identified. Yet these same source rocks are impermeable shales. How then did the fluids emigrate? It would be nice to believe that oil and gas were squeezed from the source clay during early burial before compaction destroyed permeability.

2. Secondary migration

The movement of petroleum outside of the source rock and into a reservoir bed is termed secondary migration. Siltstones, sandstones, fractured shales, limestones, chalks, dolomites, and fractured or weathered igneous and metamorphic rocks make good reservoir beds because of their high porosity.

During secondary migration, the gas and oil separate with the gas traveling out ahead of the oil. Rates are on the order of centimeters per year. Lateral migration can occur over

hundred of miles and vertical migration over thousands of kilometers. The largest petroleum deposits are the result of lateral migration because this provides drainage from a larger volume of source rock than does vertical migration. Migration pathways can change over time as chemical reactions, such as pressure solution, recrystallization, and cementation, can alter permeability.

The main force driving secondary migration is the buoyancy of hydrocarbons. There is a tendency for oil and gas to segregate from aqueous phase liquids because of density differences. In most cases, the action of gravity leads to a column of gas over oil over water. In a few cases, this does not happen and gravity migration is restricted by capillary forces. Capillary pressure is the excess pressure required for oil or gas to displace water from pores.

If the migrating petroleum encounters a relatively impermeable barrier, further movement is inhibited. The oil and gas pool behind this barrier, forming a concentrated deposit. The part of the reservoir bed where the petroleum pools is called a trap.

3. Tertiary migration

Occurs when petroleum moves from one trap to another or to a seep to the surface, either from a reservoir or source rock (Fig. 10).

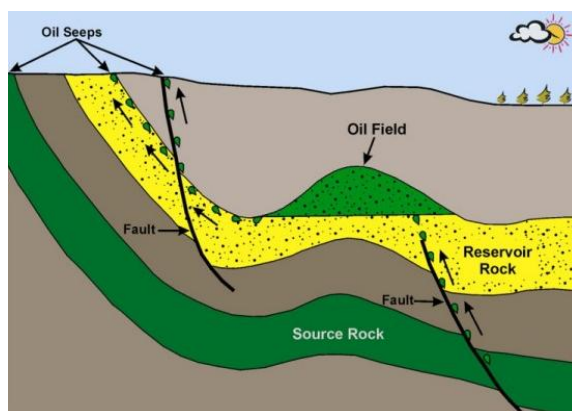


Fig. 10: Petroleum seepage.

2.4 Reservoir rock

Reservoir Rocks are the rocks that have the ability to store fluids inside its pores so that the fluids (water, oil and gas) can be accumulated. In petroleum geology, the reservoir is one of the elements of the petroleum system that can accumulate hydrocarbons (oil or gas).

Theoretically, any rock may act as a reservoir for oil or gas. In practice, the sandstones and carbonates contain the major known reserves, although fields do occur in shales and diverse igneous and metamorphic rocks. For a rock to act as a reservoir it must possess two essential properties: It must have pores to contain the oil or gas, and the pores must be connected to allow the movement of fluids; in other words, the rock must have permeability.

2.4.1 Porosity

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:

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

Pores are of three morphological types: catenary, cul-de-sac, and closed (Fig. 11). 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 are 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.

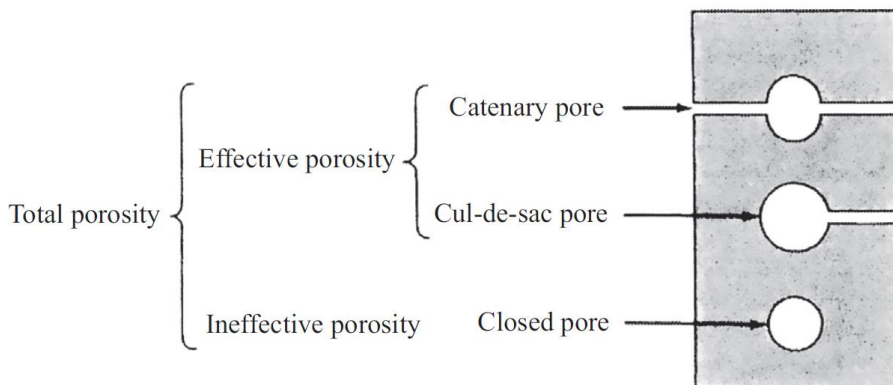


Fig. 11: Three basic types of pores.

The size and geometry of the pores and the diameter and tortuosity of the connecting throat passages all affect the productivity of the reservoir. Two main types of pore can be defined according to their time of formation. Primary pores are those formed when a sediment is deposited. Secondary pores are those developed in a rock some time after deposition.

2.4.2 Permeability

The second essential requirement for a reservoir rock is permeability. Porosity alone is not enough; the pores must be connected. Permeability is the ability of fluids to pass through a porous material (Fig. 12). The original work on permeability was carried out by H. Darcy (1856), who studied the flow rates of the springs at Dijon in France. Permeability is seldom the same in all directions within a rock. Vertical permeability is generally far lower than permeability horizontal to the bedding.

Tensile fractures and normal faults are most likely to provide flow conduits because the fractures tend to be more likely to be open. Fault breccias often provide zones of high permeability. Reverse faults tend to be less permeable than normal faults as would be

expected from the stress regime responsible for their formation. Vertical migration of fluids through fracture systems in both low permeability rocks and reservoir rocks is widely reported in the hydrogeological and petroleum geology literature.

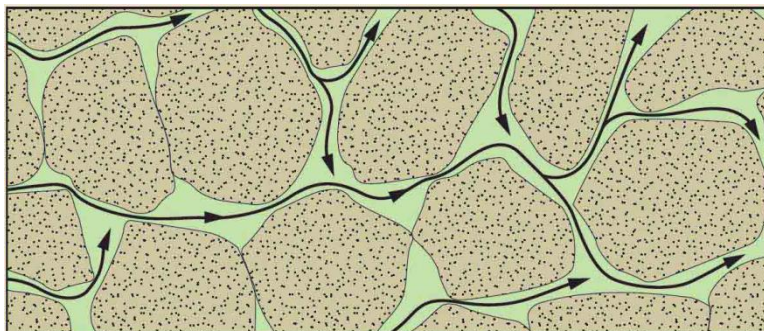


Fig. 12: Connected pores (permeability)

2.4.3 Reservoir fluid properties

Reservoir fluids are a complex mixture of many hundreds of hydrocarbon components plus a number of nonhydrocarbons. Hydrocarbons are generated in “source rock” by the breakdown of organic material at high temperature and pressure, then migrate upwards into “traps” where permeable rock above displaces the water originally present. The fluid properties of any particular mixture will depend on reservoir temperature and pressure. The nature of the hydrocarbon mixture generated will depend on the original biological material present, the temperature of the source rock and the pressure, temperature, and time taken.

Petroleum reservoirs may contain any of the three fluid phases—water (brine), oil, or gas. The initial distribution of phases depends on depth, temperature, pressure, composition, historical migration, type of geological trap, and reservoir heterogeneity (that is, varying rock properties). The forces that originally distribute the fluids are gravity, capillary, molecular diffusion, thermal convection, and pressure gradients.

2.4.4 Classification of reservoir rocks

1. Igneous Rocks: can be part of reservoirs (fractured rocks) (Fig. 13).
2. Metamorphic Rocks: Formed by the action of temperature and/or pressure on sedimentary or igneous.
3. Sedimentary Rocks: the most important for the oil industry as it contains most of the source rocks and cap rocks and virtually all reservoirs. Sedimentary rocks come from the debris of older rocks and are split into two categories (Fig. 14):
 - Clastic rocks: Formed from the materials of older rocks by the actions of erosion, transportation and deposition (mechanical process) such as conglomerate, sandstone, shale.
 - Non-clastic rocks: are formed by chemical precipitation (settling out from a solution) such as Limestone, calcite and halite.



Fig. 13: Fractures igneous rocks

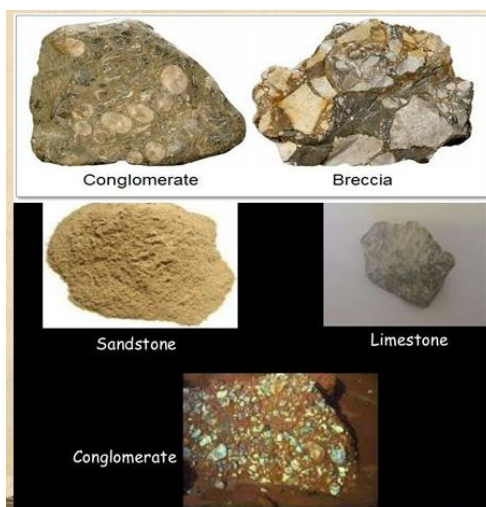


Fig. 14: Sedimentary rocks

2.5 Seal or cap rock

For a trap to have integrity it must be overlain by an effective seal (Fig. 15). Any rock may act as a seal as long as it is impermeable. Seals will commonly be porous, and may in fact be petroleum saturated, but they must not permit the vertical migration of petroleum from the trap. Shales are the commonest seals, but evaporites are the most effective. Shales are commonly porous, but because of their fine grain size have very high capillary forces that prevent fluid flow.

Analysis of seals involves assessment of their thickness and extent, such that their effectiveness can be quantified. Faults may be sealing or nonsealing, depending on whether the sand offsets sand (nonsealing) or shale (sealing) (Fig. 16). Any lithology can be a seal or flow barrier. The requirement is that the minimum capillary displacement pressure of the seal or flow-barrier material be greater than the buoyancy pressure of the hydrocarbons in the accumulation. The continuous, small, pore-throat sizes create a barrier to moving hydrocarbons, causing them to dam up or become trapped. Therefore, the size of the continuous pore throats and the density of the hydrocarbons and water are critical elements in evaluating a seal or flow barrier.

With increasing induration shales will tend to fracture when subjected to stress. Tectonic movements may thus destroy the effectiveness of a brittle shale seal, though the fractured shale may then, of course, serve as a petroleum reservoir in its own right.

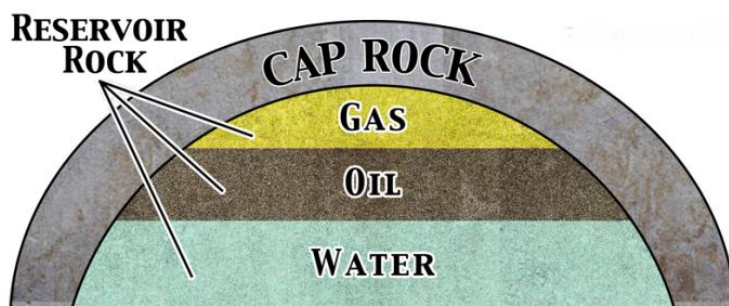


Fig. 15: Cap rock

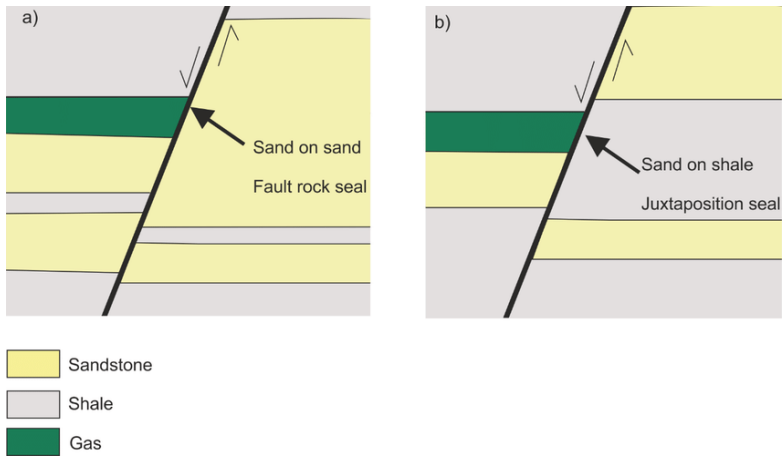


Fig. 16: Concept of fault rock seal

2.6 Traps

The term trap was first applied to a hydrocarbon accumulation by Orton (1889): “stocks of oil and gas might be trapped in the summits of folds or arches found along their way to higher ground.” A trap is one of the seven essentials requisites for a commercial accumulation of oil or gas. Levorsen (1967) gave a concise definition of a trap as “the place where oil and gas are barred from further movement.” A trap can also be defined as any geometric arrangement of rock, regardless of origin, that permits significant accumulation of oil or gas, or both, in the subsurface.

Explorationists in general and geophysicists in particular search for hydrocarbon traps. Perhaps it would be more accurate to say that they search for potential traps. Traps consist of porous reservoir rocks overlain by tight (low permeability) rocks which do not allow oil or gas to pass. These must form structures closed at the top such that they collect oil and gas, which is lighter than water. So, it is clear that to be a viable trap, this requires two fundamental components: a reservoir rock in which to store the hydrocarbon, and a seal to keep the hydrocarbons from migrating out of the trap.

2.6.1 Nomenclature of trap

Many terms are used to describe the various parameters of a trap. These terms are defined as follows and illustrated with reference to an anticlinal trap, the simplest type (Fig. 17). The highest point of the trap is the crest, or culmination. The lowest point at which hydrocarbons may be contained in the trap is the spill point; this lies on a horizontal contour, the spill plane. The vertical distance from crest to spill plane is the closure of the trap. A trap may or may not be full to the spill plane, a point of both local and regional significance. The zone immediately beneath the petroleum is referred to as the bottom water, and the zone of the reservoir laterally adjacent to the trap as the edge zone.

Within the trap the productive reservoir is termed the pay. The vertical distance from the top of the reservoir to the petroleum/water contact is termed gross pay. This thickness may vary from only 1 or 2 m in Texas to several hundred meters in the North Sea and Middle East. All of the gross pay does not necessarily consist of productive reservoir, however, so gross pay is usually differentiated from net pay. The net pay is the cumulative vertical thickness of a reservoir from which petroleum may be produced.

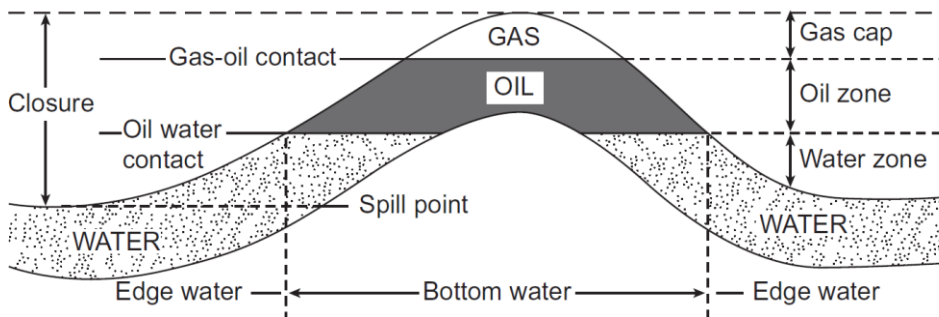


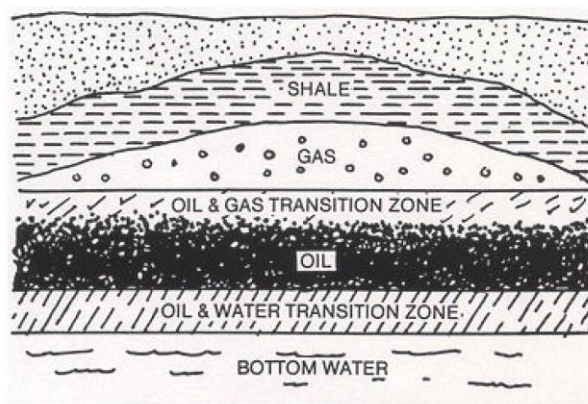
Fig. 17: Cross section through a simple anticlinal trap

2.6.2 Distribution of petroleum within a trap

A trap may contain oil, gas, or both. The oil:water contact (commonly referred to as OWC) is the deepest level of producible oil. Similarly, the gas:oil contact (GOC) or gas:water contact, as the case may be, is the lower limit of producible gas. The accurate evaluation of these surfaces is essential before the reserves of a field can be calculated, and their establishment is one of the main objectives of well logging and testing.

Where oil and gas occur together in the same trap, the gas overlies the oil because the gas has a lower density (Fig. 18). Whether a trap contains oil and/or gas depends both on the chemistry and level of maturation of the source rock and on the pressure and temperature of the reservoir itself. Boundaries between oil, gas, and water may be sharp or transitional. Abrupt fluid contacts indicate a permeable reservoir; gradational ones indicate a low permeability with a high capillary pressure.

Fig. 18: Petroleum distribution within a trap



2.6.3 Classification of traps

Hydrocarbons may be trapped in many different ways. Several schemes have been drawn up to attempt to classify traps. Most trap classificatory schemes are based on the geometry of the trap. Two major genetic groups of trap are generally agreed on: structural and stratigraphic. A third group, combination traps, is caused by a combination of processes. Agreement breaks down, however, when attempts are made to subdivide these groups.

Structural traps are those traps whose geometry was formed by tectonic processes after the deposition of the beds involved. According to Levorsen (1967), a structural trap is “one whose upper boundary has been made concave, as viewed from below by some local deformation, such as folding, or faulting, or both, of the reservoir rock.” Basically, therefore, structural traps are caused by folding and faulting.

A second group of traps is caused by diapirs, where salt or mud have moved upward and domed the overlying strata, causing many individual types of trap. Arguably, diapiric traps are a variety of structural traps; but since they are caused by local lithostatic movement, not regional tectonic forces, they should perhaps be differentiated.

Stratigraphic traps are those traps whose geometry is formed by changes in lithology. The lithological variations may be depositional (e.g., channels, reefs, and bars) or postdepositional (e.g., truncations and diagenetic changes).

The final group, combination traps, is formed by a combination of two or more of the previously defined genetic processes. The various types of traps-structural, diapiric, stratigraphic, and combinationdare described and illustrated with examples in the following sections.

A) Structural traps

As previously stated, the geometry of structural traps is formed by postdepositional tectonic modification of the reservoir. Structural traps divides into those caused by folding and those caused by faulting.

1. Anticlinal Traps

Anticlinal, or fold, traps were from the first type of petroleum traps recognized (Fig. 19). Anticline and folds are formed by compression. Anticlinal traps are by far the most important structural traps. The rock layers in an anticlinal trap were originally laid down horizontally then folded upward into an arch or dome. Later, hydrocarbons migrate into the porous and permeable reservoir rock. A cap or seal (impermeable layer of rock) is required to permit the accumulation of the hydrocarbons.

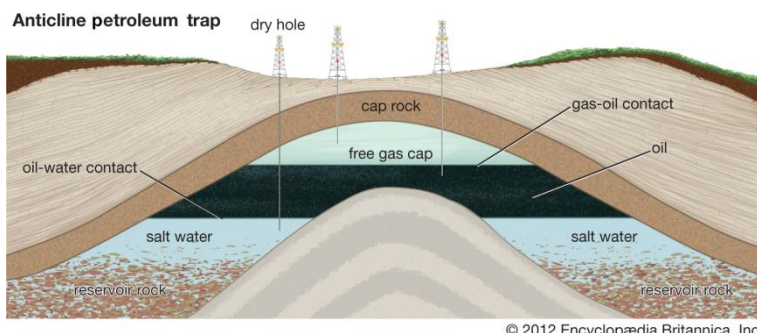


Fig. 19: Anticlinal trap

One of the best known oil provinces with production from compressional anticlines occurs in Iran. Many such fields are found in the foothills of the Zagros Mountains. Sixteen of these fields are in the “giant” category, with reserves of more than 500 million barrels of recoverable oil or 3.5 trillion cubic feet of recoverable gas. The main producing horizon is the Asmari limestone (Lower Miocene), a reservoir with extensive fracture porosity. The cap rock is provided by evaporites of the lower Fars Group (Miocene). Individual anticlines are up to 60 km in length and some 10 - 15 km wide.

2. Fault traps

As already pointed out, faults can be extremely important to the viability of a trap by providing either seals or leak points. They are capable of acting as top, lateral, or base seals by juxtaposing relatively impermeable rock units against more permeable reservoir units or by acting as sealing surfaces due to the impermeable nature of the material along the fault. In addition, they may act as leak points by juxtaposition of permeable units or by creation of a fracture network. Structural traps that are dominated by faults at the reservoir-seal level (the fault itself makes the trap by sealing the reservoir without an ancillary fold) can be divided into three categories based on the type of separation, or slip if it is known, that geologic surfaces exhibit across the fault. These are normal, reverse, and strike separation or slip fault traps.

a. Normal fault traps:

Are the most common fault dominated structural traps. They are commonly occurs in response to extension (Fig. 20).

b. Reverse fault traps:

Commonly associated with compressional tectonics (Fig. 21).

c. Fractures and joints:

Fine grained rocks may be porous, but they will not be reservoir rocks because they lack permeability. Shales and chinks (fine grained limestone composed of

microfossils) are good examples of this. If the fine grained rock is naturally fractured, however, it has permeability and can be reservoir rock (Fig. 22).

Fractured or joints are formed when the rock is stressed. This occurs when the rock is disturbed by deformation (folding or faulting). Fractures have the highest probability of occurring where the rock is bent the most on fold. Fractures also possibly occur along a fault plane where the two blocks grind against each other during the fault movement.

Petroleum traps in the Austin Chalk occur near Giddings and La Grange in south central Texas. The Mount Calm oil field is typical of this type of trap. Fault movement has fractured the Austin Chalk adjacent to the fault plane and the oil field occurs in the fractured chalk.

Fig. 20: Normal fault trap
(extensional regime)

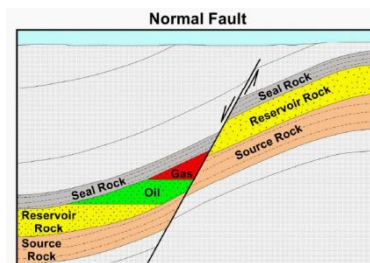


Fig. 21: Reverse fault trap
(thrust)

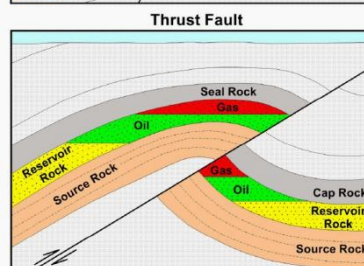
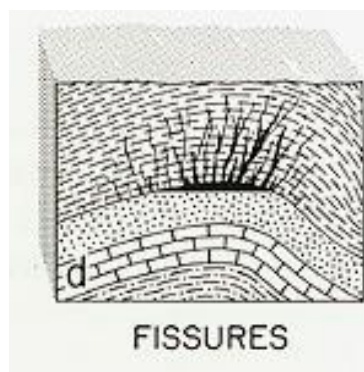
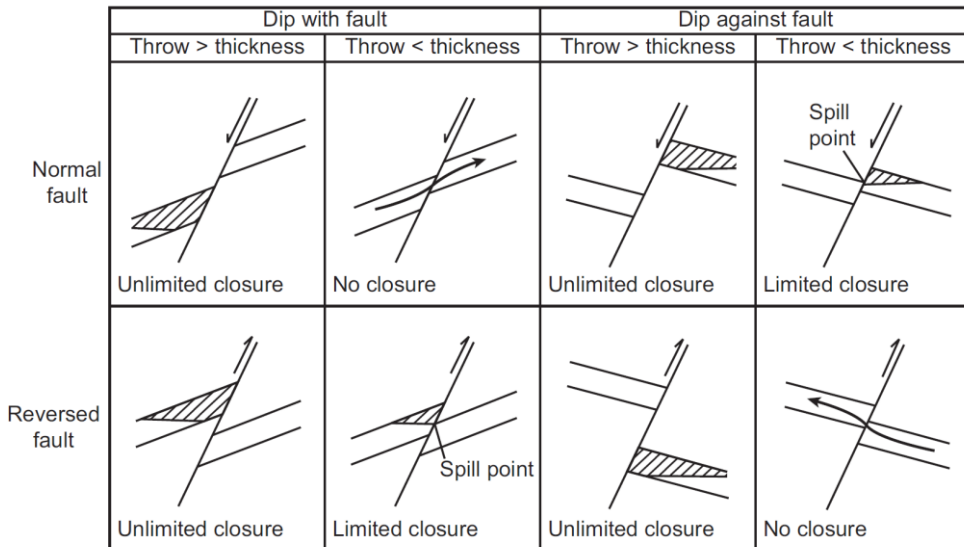


Fig. 22: Fractures trap



The eight theoretical configurations of petroleum traps associated with faulting are shown in Fig. 23. These configurations are drawn on the assumption that oil can move across, but not up, the fault plane when permeable sands are juxtaposed.



Assumption: Shale against sand is sealing.
Sand against sand is nonsealing.

Fig. 23: The eight theoretical configurations of petroleum traps associated with faulting.

B) Stratigraphic traps

Another major group of traps to be considered are the stratigraphic traps, whose geometry is due to changes in lithology. Such changes may be caused by the original deposition of the rock, as with a reef or channel. Alternatively, the change in lithology may be postdepositional, as with a truncation or diagenetic trap.

Stratigraphic traps are less well known and harder to locate than structural traps; their formation processes are even more complex. Nonetheless, as with structural traps a broad classification of different types can be made.

1. Stratigraphic Traps Unrelated to Unconformities (primary stratigraphic trap):

In this group the major distinction is between traps due to deposition and traps due to diagenesis. The depositional traps include channels, bars, and reefs. Diagenetic traps are due to porosity and permeability changes caused by solution and cementation. These various types of traps are discussed and illustrated as follows.

a. Channel Traps:

A channel is an environment for the transportation of sand, which may or may not include sand deposition (Fig. 24). Thus, whereas a barrier island will always be made of sand, channels are frequently clay plugged. This situation is not necessarily bad, because the channel fill may act as a permeability barrier and thus trap hydrocarbons in adjacent porous beds. Therefore, finding a channel is not a guarantee of finding a reservoir.

Fig. 24: Channel trap

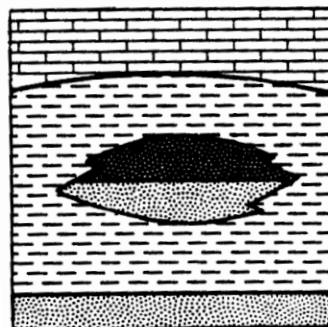


b. Barrier bar traps:

Marine barrier bar sands often make excellent reservoirs because of their clean, well-sorted texture (Fig. 25). It is usually long, narrow lenses of sand encased in a shale layer. These are deposited as shorelines (beaches, barrier islands), rivers, and deltas. Sometimes, however, isolated barrier bars may be totally

enclosed in marine and lagoonal shales. These barrier bars may then form shoestring stratigraphic traps parallel to the paleoshoreline.

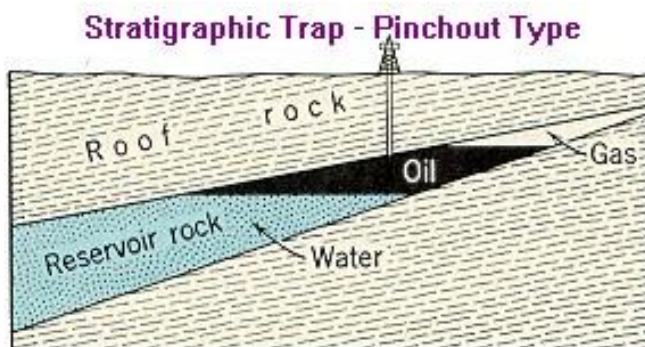
Fig. 25: Barrier bar sand trap.



c. Pinchout traps:

A type of stratigraphic trap. The termination by thinning or tapering out ("pinching out") of a reservoir against a nonporous sealing rock creates a favorable geometry to trap hydrocarbons, particularly if the adjacent sealing rock is a source rock such as a shale (Fig. 26). A sandstone pinchout or wedge in a shale layer will trap any petroleum rising up the dip of the sandstone in a landward direction.

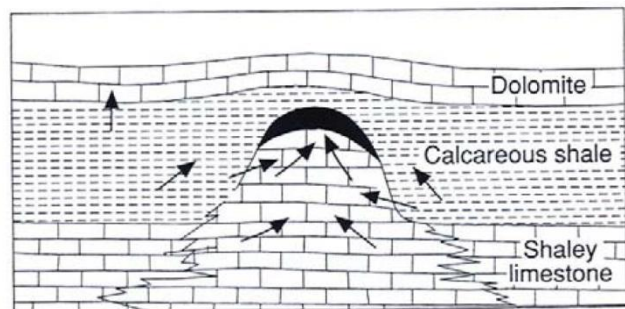
Fig. 26: Pinchout trap



d. Reefs:

Reefs, or carbonate buildups, have long been recognized as one of the most important types of stratigraphic traps. Reefs develop as domal (pinnacle) and elongated (barrier) antiforms (Fig. 27). They grow a rigid stony framework with high primary porosity, and they are frequently transgressed by marine shales, which may act as hydrocarbon source rocks. Many reef fields occur in the Sirte Basin of Libya, each reef is only about 5 km in diameter, but up to 400 m thick.

Fig. 27: Reef trap



e. Facies changes:

May juxtapose potential reservoir rocks and impermeable seal rocks over relatively short lateral distances in either siliciclastic or carbonate settings. The lateral transition from reservoir to seal is generally gradational, leading to possible noneconomic segments within the reservoir (Fig. 28). Particular care must be taken to identify strike closure in this type of trap.

Fig. 28: Facies change trap



2. Stratigraphic Traps Related to Unconformities (secondary stratigraphic trap):

The role of unconformities in the entrapment of hydrocarbons has been remarked by geologists. Unconformities facilitate the juxtaposition of porous reservoirs and impermeable shales that may act as source and seal (Fig. 29). A large percentage of the known global petroleum reserves are trapped adjacent to the worldwide unconformities and source rocks of Late Jurassic to mid-Cretaceous age. Many of these reserves are held in structural and combination traps, as well as the pure stratigraphic traps. Unconformity-related traps can be divided into those that occur above the unconformity and those that occur below it (Fig. 30).

Fig. 29: Angular unconformity trap

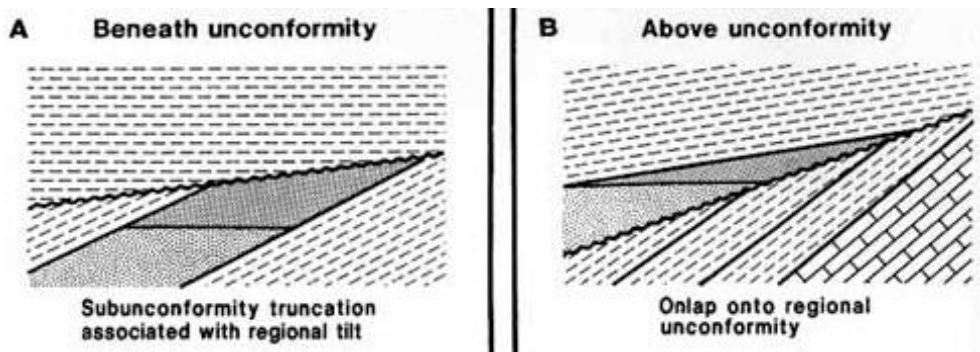
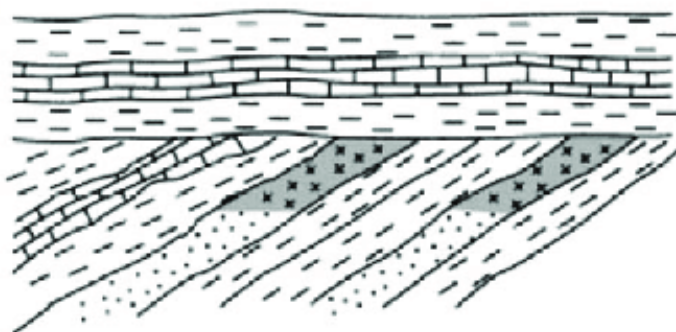


Fig. 30: Above and below unconformity trap.

C) Combination traps

Many oil and gas fields around the world are not due solely to structure or stratigraphy flow, but to a combination of two or more of these forces. Such fields may properly be termed combination traps. Most of these traps are caused by a combination of structural and stratigraphical processes. Examples can be the salt dome, many types of traps can be found near salt domes. Most would be considered structural, although some could be classified as combination traps.

Salt domes are large masses of salt rising from the subsurface through overlying sediments to form a plug-shaped structure (Fig. 31). Salt is a type of solid that flows slowly as a viscous liquid under pressure. Many areas are underlain by thick salt deposits. When salt is originally deposited, it has a density of 2.2 grams per cubic centimeter. It is then buried by loose sediments such as sands and muds with original densities of 1.9 grams per cubic centimeter. As the clay and sand are buried, however, they compact, losing porosity and gaining density. Ultimately, a burial depth is reached when sediments are denser than salt. Depending on a number of variables, this point may occur between about 800 and 1200 m. When this point is reached, the salt will tend to flow up through the denser overburden.

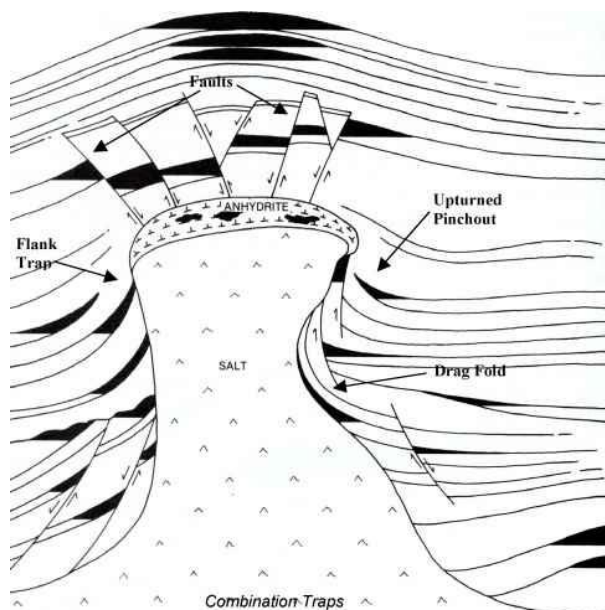


Fig. 31: Combination trap (Salt dome)

In some salt structures the overlying strata are only updomed. In the simplest cases subcircular anticlines may trap hydrocarbon over the crest of a salt dome. The crestal dome may be complicated by radial faults or a central graben. Around the flank of the dome, oil or gas can be trapped by faults, both sediment against sediment and sediment against salt, and by stratigraphic truncation, pinchout, and onlap. Some salt domes are pear or mushroom shaped in cross section, and petroleum is trapped beneath the peripheral overhang zone. Fig. 32 show the different traps related to the salt dome shape.

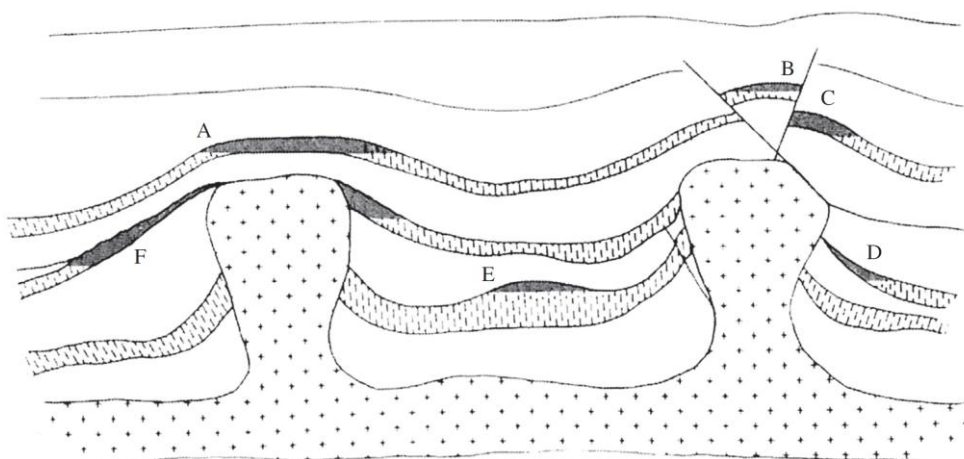


Fig. 32: Crustal cross section illustrating the various types of trap that may be associated with salt movement: (A) domal trap; (B and C) fault traps; (D) pinchout trap; (E) turtle-back or sedimentary anticline; and (F) truncation trap.

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