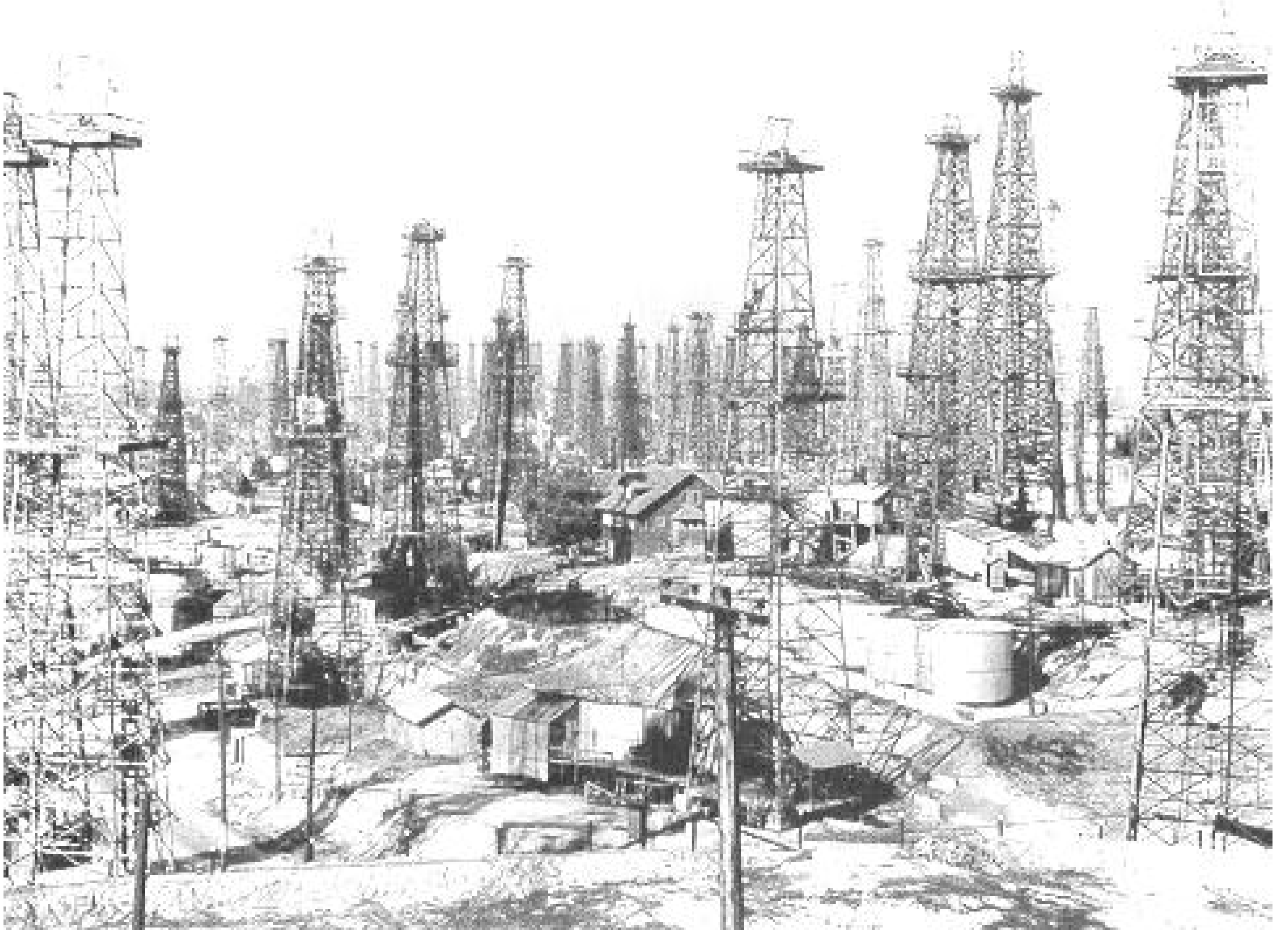
Basic Petroleum Geology and Log Analysis



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Introduction

Geology is the science that deals with the history and structure of the earth and its life 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.

Objectives

After completing this section, you should be able to:

- Define Geology and how it applies to the petroleum industry.
- Define and describe the three basic layers of Earth.
- Differentiate between weathering processes and erosional processes
- 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.
- List and describe the basic hydrocarbon traps.
- Name the different geological mapping techniques used in petroleum exploration.
- Explain the difference between surface and subsurface exploration.
- Explain the basic concepts of well log analysis.

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.

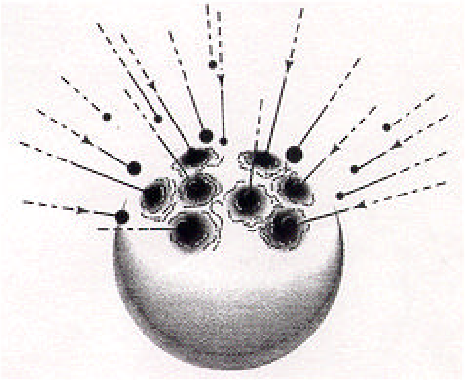


Figure 1 Collision of material onto primative Earth

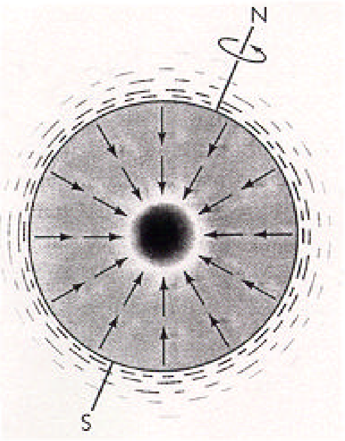


Figure 2 Compression of material

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. 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.

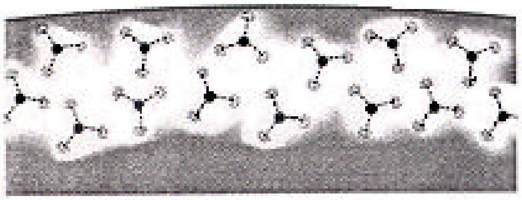


Figure 3 Disintegration of radioactive elements

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 (8-11 km) — and is made up primarily of heavy rock that is formed when molten rock (magma) cools. 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.

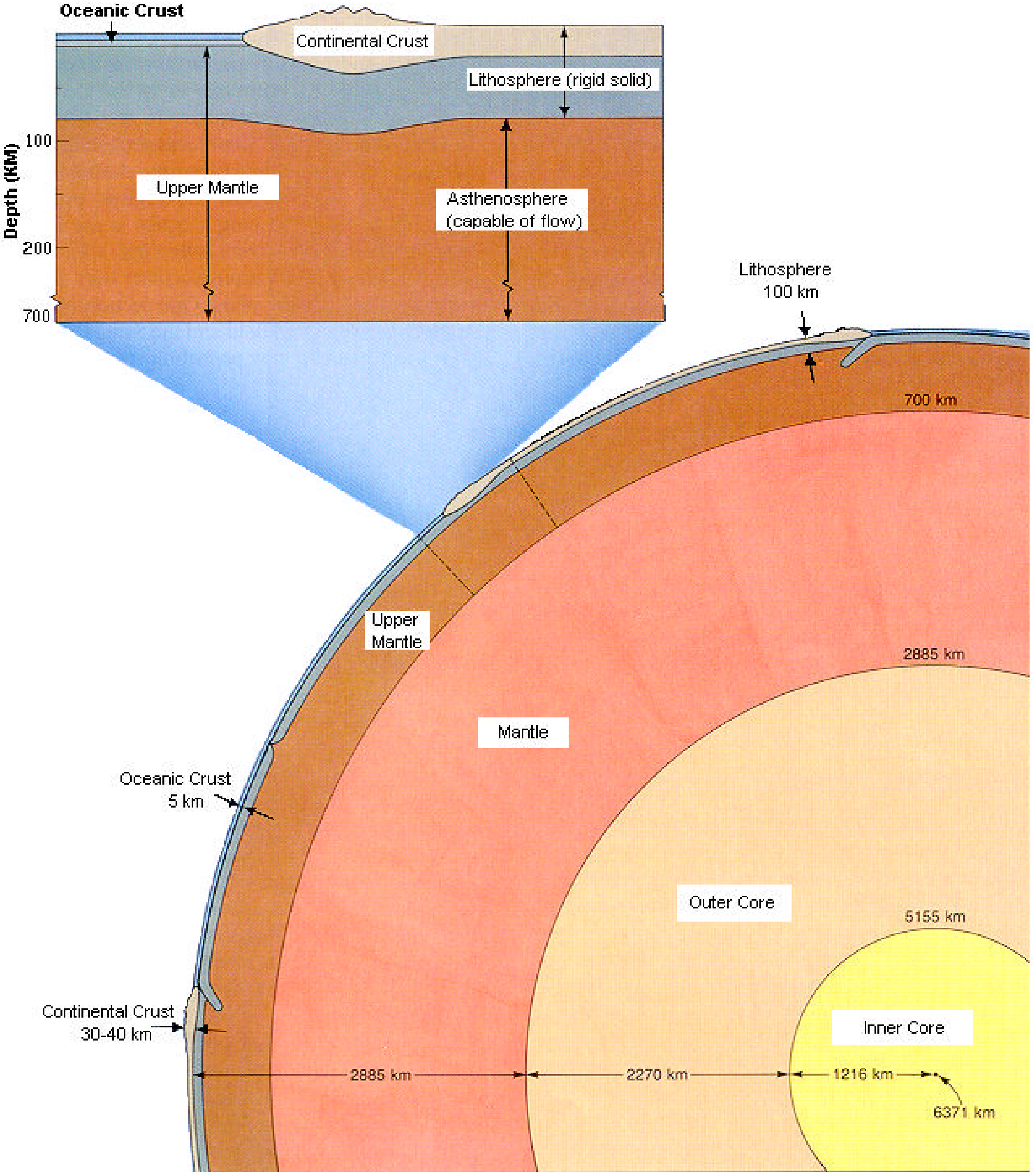


Figure 4 Cross-sectional view of the earth showing internal structure

The crust is continuously changing and moving because of two major forces of nature—**Orogeny** and **weathering/erosion**. 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:

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

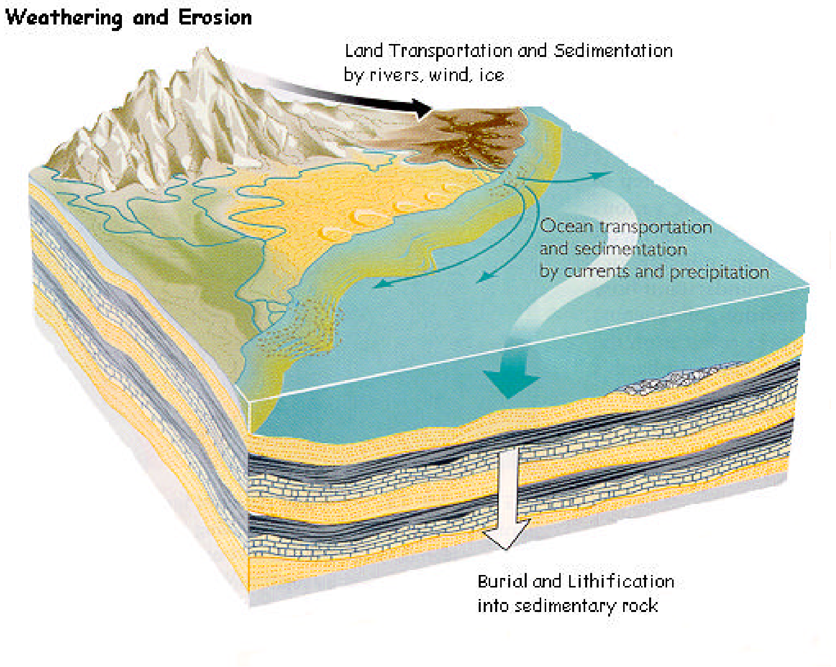


Figure 5

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.

Three Basic Rock Types

The earth's crust is composed of three basic rock types: igneous, sedimentary and metamorphic.

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.

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.

Sedimentary rocks are formed as sediments, either from eroded fragments of older rocks or chemical precipitates. Sediments lithify by both compaction, 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.

Petroleum-Bearing Rocks

Sedimentary rocks are the most important and interesting type of rock to the petroleum industry because most oil and gas *accumulations* **occur in them; igneous and metamorphic rocks rarely contain oil and gas.**

All petroleum *source rocks* **are sedimentary.**

Furthermore, most of the world's oil lies in sedimentary rock formed from marine sediments deposited on the edges of continents. For example, there are many large deposits that lie along the Gulf of Mexico and the Persian Gulf.

The Rock Cycle

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.

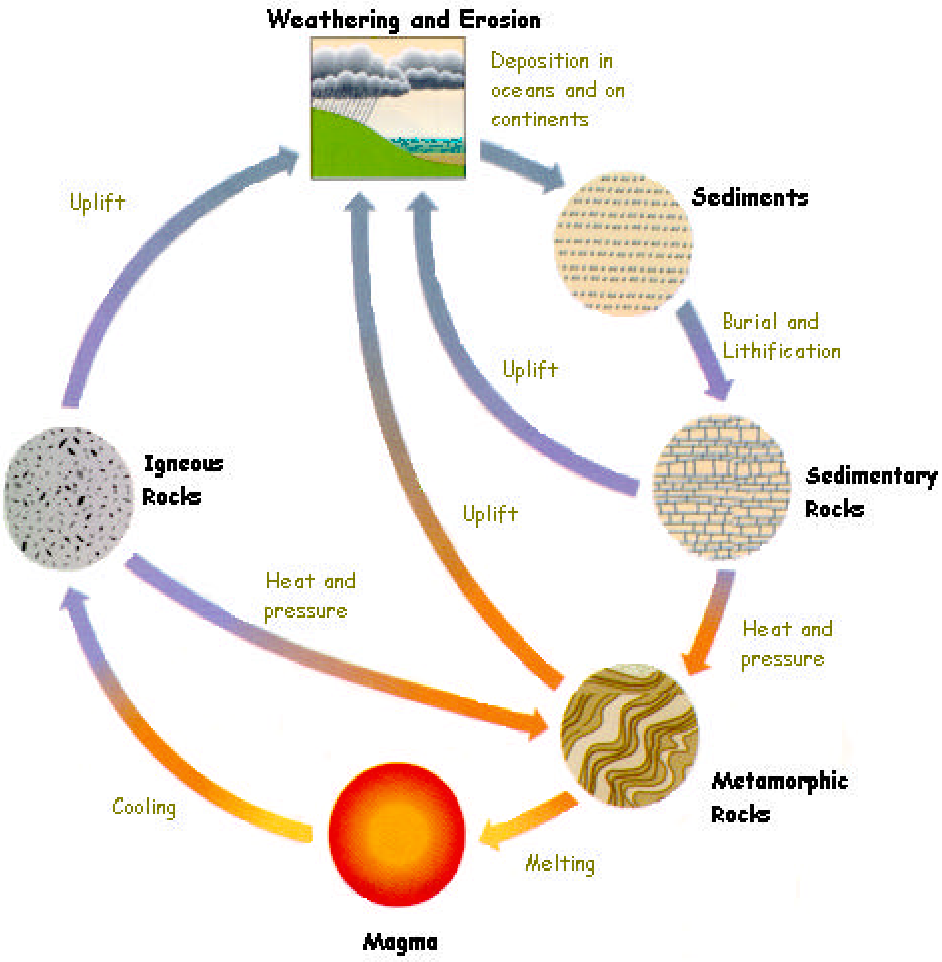


Figure 6 The rock cycle

Geologic Time

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 uniformitarianism**. 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."

Age Dating

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 radiochronology 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.

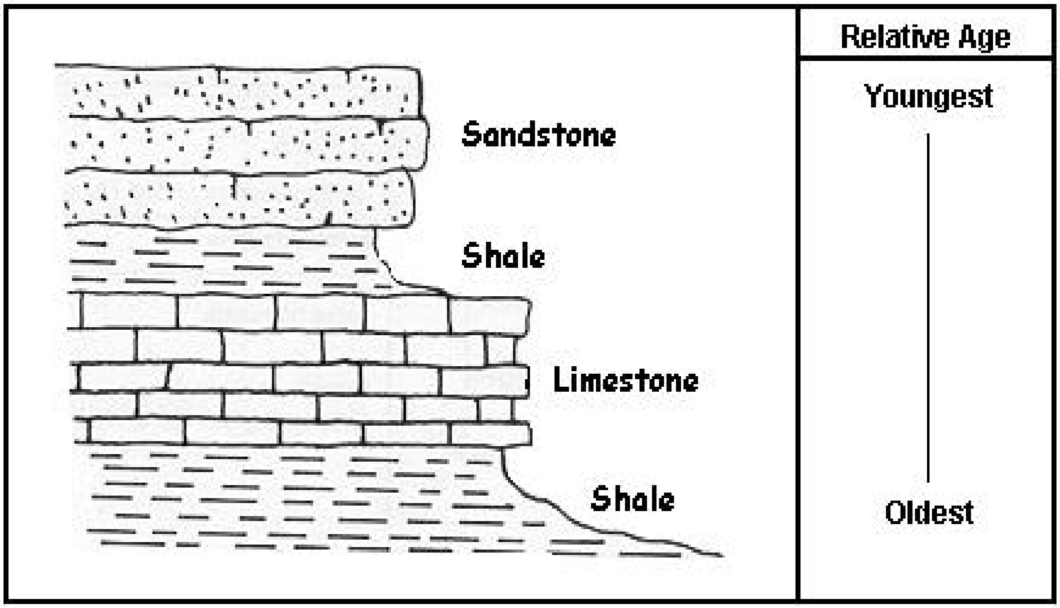


Figure 7 Layered rock sequence illustrating relative age and deposition of strata in horizontal layers

Basic Age Dating Principles

To establish a relative time scale, a few simple principle or rules had to be discovered and applied. Although they may seem rather obvious to us today, their discovery was a very important scientific achievement.

Stratigraphy is the study of the origin, composition, distribution, and sequence of layers of sedimentary rock, or strata. Stratification is the characteristic layering or bedding of sedimentary rocks. This characteristic is basic to two of the principles used to interpret geologic events from the sedimentary rock record. First is the **principle of original horizontality,** which states that most layers of sediment are deposited in a nearly horizontal layer. If a sequence of sedimentary rock layers are folded or tilted, then generally it is understood that these layers were deformed by tectonic events after their initial deposition. Second is the **principle of superposition** which states that each layer of sedimentary rock in a sequence that *has not been tectonically disturbed* is younger than the layer beneath it and older than the layer above it. Therefore, a series of sedimentary layers can be viewed as a vertical time line. This produces either a partial or complete record of the time elapsed from the deposition of the lowermost bed to the deposition of the uppermost bed. This rule also applies to other surface deposited materials such as lava flows or beds of ash from volcanic events. If igneous intrusions or faults cut through strata, they are assumed to be younger than the structures they cut and is known as the principle of **cross-cutting relationships**.

Paleontology, the study of life in past geologic time, based on fossil plants and animals, is an important consideration in the stratigraphic record and is significant in assigning ages to rock units. In early geologic endeavors, index fossils (fossils with narrow vertical stratigraphic ranges) represented the only means for realistic correlation and age assignment of rock sequences. Correlation is the process of relating rocks at one site with those at another site.

In 1793, William Smith, a surveyor working in southern England, recognized that fossils could be used to date the relative ages of sedimentary rocks. He learned that he could map rock units from coal quarry to coal quarry over a large distance if he characterized the layers by their lithology and fossil content. While mapping the vertical rock sequences he established a general order of fossils and strata from the oldest at the bottom to the youngest at the top. This stratigraphic ordering of fossils eventually became known as the principle of faunal succession and states that fossil faunas and floras in stratigraphic sequence succeed one another in a definite, recognizable order.

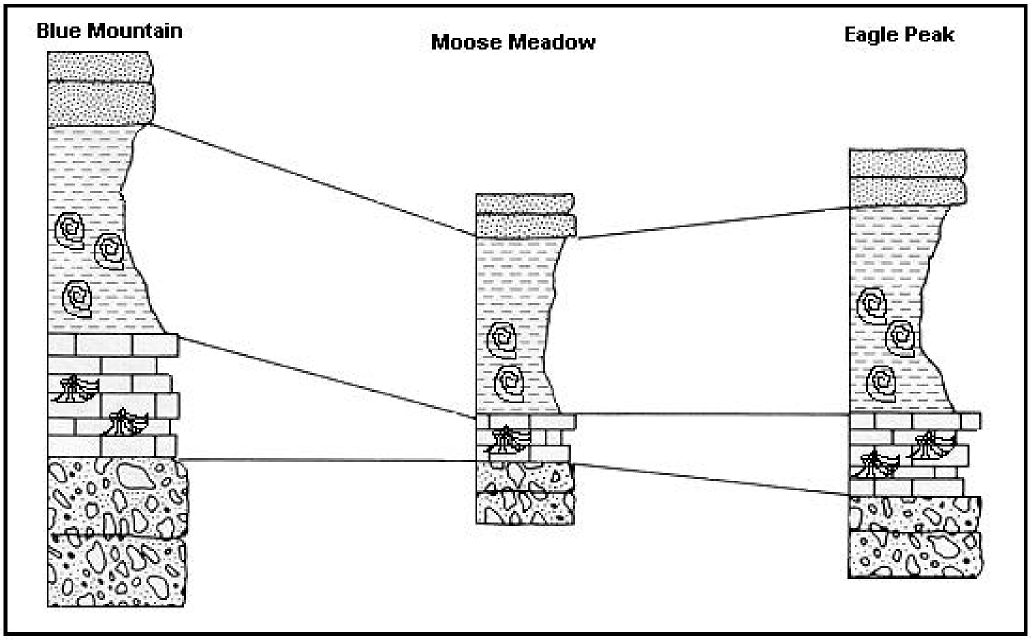


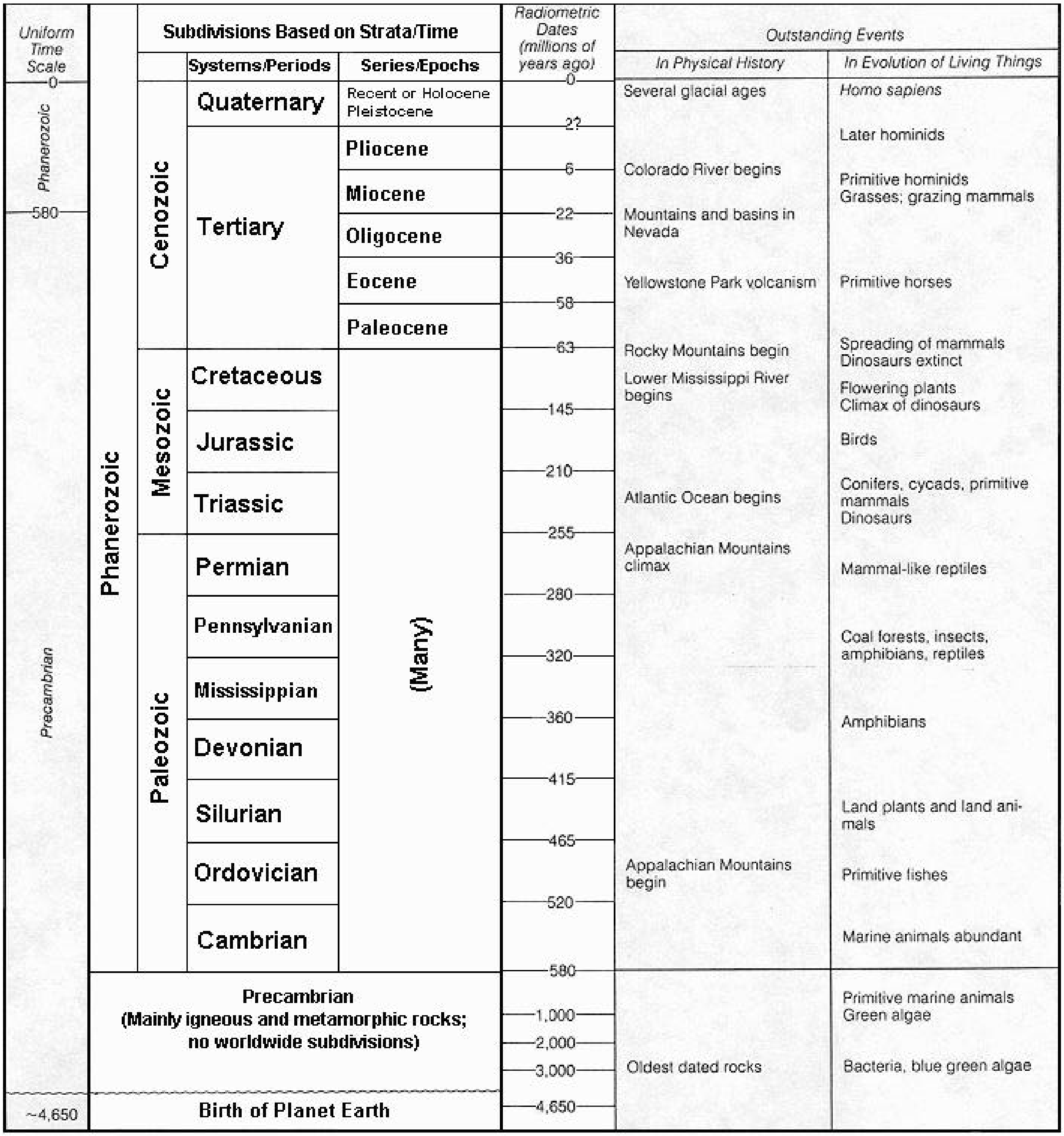
Figure 8 Correlation of strata.

Smith was also the first person to define formations within a rock unit. A formation is a rock unit that is mappable over a laterally extensive area and has the same physical properties and contains the same fossil assemblages. Some formations consist of one rock type, like limestone. Others may be interbedded, for example, alternating layers of sandstone and shale, but can be mapped as one unit.

By combining faunal succession and stratigraphic sequences, geologists can correlate formations in a local area or around the world. The petroleum industry relies on the application of these principles for exploration and production.

Geologic Time Scale

During the nineteenth and twentieth centuries, 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.



Uniform Time Scale
0
Phanerozoic
580
Precambrian
~4,650

Eon	Era	Systems/Periods	Series/Epochs	Radiometric Dates (millions of years ago)	Outstanding Events: In Physical History	Outstanding Events: In Evolution of Living Things
Phanerozoic	Cenozoic	Quaternary	Recent or Holocene Pleistocene	0 2?	Several glacial ages	Homo sapiens
		Tertiary	Pliocene	6		Later hominids
			Miocene	22	Colorado River begins	Primitive hominids Grasses; grazing mammals
			Oligocene	36	Mountains and basins in Nevada	
			Eocene	58	Yellowstone Park volcanism	Primitive horses
			Paleocene	63		
	Mesozoic	Cretaceous	(Many)	145	Rocky Mountains begin Lower Mississippi River begins	Spreading of mammals Dinosaurs extinct Flowering plants Climax of dinosaurs
		Jurassic		210		Birds
		Triassic		255	Atlantic Ocean begins	Conifers, cycads, primitive mammals Dinosaurs
	Paleozoic	Permian		280	Appalachian Mountains climax	Mammal-like reptiles
		Pennsylvanian		320		Coal forests, insects, amphibians, reptiles
		Mississippian		360		
		Devonian		415		Amphibians
		Silurian		465		Land plants and land animals
		Ordovician		520	Appalachian Mountains begin	Primitive fishes
		Cambrian		580		Marine animals abundant
Precambrian (Mainly igneous and metamorphic rocks; no worldwide subdivisions)				1,000 2,000 3,000	Oldest dated rocks	Primitive marine animals Green algae Bacteria, blue green algae
Birth of Planet Earth				4,650		

Figure 9 Geologic Time Scale

Distribution of oil and gas fields based on geologic age

It is important to know the geologic age of reservoir rocks because rocks of different ages frequently have different petroleum characteristics and productivity. It is also important to note that the age of the rock does not necessarily coincide with the time of oil accumulation. You can only know that it accumulated sometime after the formations deposition.

Table 1 Illustrates the distribution of ***discovered*** *oil and gas fields based on geologic age*

Geologic Age	% of Fields
Neogene	18
Palaeogene	21
Cretaceous	27
Jurassic	21
Permo-Triassic	6
Carboniferous	5
Devonian	1
Cambrian-Silurian	1 Total 100

Basic Classification and Types of Sedimentary Rocks

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

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 divided into 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, a quartz-rich sandstone or a feldspar-rich sandstone.

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.

There are five types of sedimentary rocks that are important in the production of hydrocarbons:

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.

Carbonates, broken into two categories**, limestones and dolomites.**

Carbonates are sediments formed by a mineral compound characterized by a fundamental anionic structure of CO_3^{-2}. Calcite and aragonite $CaCO_3$, are examples of carbonates. *Limestones* are sedimentary rocks consisting chiefly of the mineral calcite (calcium carbonate, $CaCO_3$), 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 $CaMg(CO_3)_2$. A sedimentary rock will be named dolomite if that rock is composed of more than 90% mineral dolomite and less than 10% mineral calcite.

Shales

Shale is a type of detrital sedimentary rock formed by the consolidation of fine-grained material including clay, mud, and silt and have 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 a shale is fractured, it would have the potential to be a reservoir.

Evaporites

Evaporites 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 make excellent 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 overhangs create another type of trapping mechanism.

Source Rock and Hydrocarbon Generation

Source rock refers to the formation in which oil and gas originate. Hydrocarbons are generated when large volumes of microscopic plant and animal material are deposited in marine, deltaic, or lacustrine (lake) environments. The organic material may either originate within these environments and/or may be carried into the environment by rivers, streams or the sea. The microscopic plant and animal material generally is deposited with fine clastic (**silt and/or clay**) sediments. During burial the sediments protect the organic material by creating an anoxic (oxygen depleted) environment. This allows the organic material to accumulate rather than be destroyed by aerobic organisms such as bacteria. Over time, the organic remains are altered and transformed into gas and oil by the high temperatures and increased pressure of deep burial. This process can take tens of thousands of years to occur. The amount of petroleum generated is a function of the thickness of the accumulated sediments and organic material, the burial of these materials, and time.

Organically rich, black-colored shales deposited in a quiet marine, oxygen depleted environment are considered to be the best source rocks.

Migration of Hydrocarbons

Primary migration is the process by which petroleum moves from source beds to reservoir rocks. Secondary migration is the concentration and accumulation of oil and gas in reservoir rock. Evidence that petroleum does migrate is suggested by the very common occurrence of active seeps where oil and gas come to the surface either directly from the source rock or from reservoir rocks. In either case, the petroleum had to migrate through rocks with enough permeability and porosity to allow the fluids to flow to the surface. Therefore, migration involves rock properties and fluid properties, including the petroleum, moving through the rocks. Some of the rock and fluid properties include porosity, permeability, capillary pressure, temperature and pressure gradients, and viscosity. These and other properties will be discussed in detail in the sections to follow.

Basic Hydrocarbon Chemistry

Petroleum is a general term for all naturally occurring hydrocarbons, whether gaseous, liquid, or solid. It is both simple and complex and is composed almost entirely of carbon and hydrogen. Impurities like, nitrogen, sulfur, and oxygen play a somewhat important role in the formation of hydrocarbon molecules. The numerous varieties of petroleum are due to the way carbon and hydrogen can combine and form different sized molecules, thus creating different molecular weights. A thick black asphalt and yellow light crude are examples of two varieties of petroleum with different molecular weights.

A hydrocarbon molecule is a chain of one or more carbon atoms with hydrogen atoms chemically bonded to them. At room temperature and pressure, molecules with up to four carbon atoms occur as gases; molecules having five to fifteen carbon atoms are liquids; and the heavier molecules with more than fifteen carbon atoms occur as solids. Some petroleum contains hydrocarbon molecules with up to sixty or seventy carbon atoms. The molecular structure of hydrocarbons can vary from simple straight chains to more complex branched chains or closed-ring structures.

Temperature affects the chemical structure of hydrocarbons and can break heavier long-chain molecules into smaller and lighter molecules. For a more detailed explanation of the chemical properties of hydrocarbons, refer to Appendix A.

Five Major Types of Hydrocarbons of Interest to Petroleum Exploration

Kerogen/Bitumens

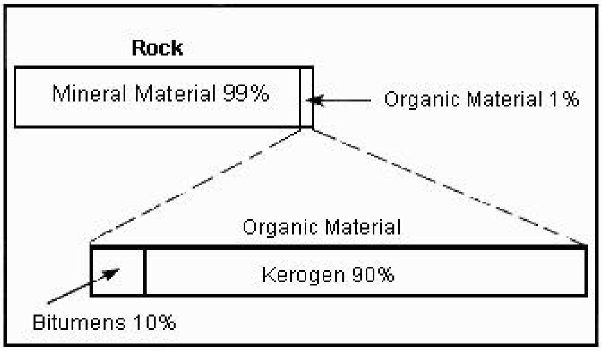


Figure 10

Shale rock volume is composed of 99% clay minerals and 1% organic material. We have seen that petroleum is derived mainly from lipid-rich organic material buried in sediments. Most of this organic matter is in a form known as kerogen. **Kerogen** is that part of the organic matter in a rock that is insoluble in common organic solvents. It owes its insolubility to its large molecular size and heat is required to break it down. Maturation of kerogen is a function of increased burial and temperature and is accompanied by chemical changes. As kerogen thermally matures and increases in carbon content, it changes form an immature light greenish-yellow color to an overmature black, which is representative of a progressively higher coal rank. Different types of kerogen can be identified, each with different concentrations of the five primary elements, carbon, hydrogen, oxygen, nitrogen, and sulphur, and each with a different potential for generating petroleum.

The organic content of a rock that is extractable with organic solvents is known as **bitumen**. It normally forms a small proportion of the total organic carbon in a rock. Bitumen forms largely as a result of the breaking of chemical bonds in kerogen as temperature rises. Petroleum is the organic substance recovered from wells and found in natural seepages. Bitumen becomes petroleum at some point during migration. Important chemical differences often exist between source rock extracts (bitumen) and crude oils (petroleum).

Kerogen is of no commercial significance except where it is so abundant (greater than 10%) as to occur in oil shales. It is, however, of great geological importance because it is the substance that generates hydrocarbon oil and gas. A source rock must contain significant amounts of kerogen.

Crude Oil

Crude oil is a mixture of many hydrocarbons that are liquid at surface temperatures and pressures, and are soluble in normal petroleum solvents. It can vary in type and amount of hydrocarbons as well as which impurities it may contain.

Crude oil may be classified chemically (e.g. paraffinic, naphthenic) or by its density. This is expressed as specific gravity or as API (American Petroleum Institute) gravity according to the formula:

$$\text{API}^{o} = \frac{141.5}{\text{sp. grav.} @ 60^{o}\,\text{F}} - 131.5$$

Specific gravity is the ratio of the density of a substance to the density of water.

API gravity is a standard adopted by the American Petroleum Institute for expressing the specific weight of oils.

The lower the specific gravity, the higher the API gravity, for example, a fluid with a specific gravity of 1.0 g cm^{-3} has an API value of 10 degrees. ***Heavy oils*** are those with API gravities of less than 20 (sp. gr. >0.93). These oils have frequently suffered chemical alteration as a result of microbial attack (biodegradation) and other effects. Not only are heavy oils less valuable commercially, but they are considerably more difficult to extract. API gravities of 20 to 40 degrees (sp. gr. 0.83 to 0.93) indicate ***normal oils***. Oils of API gravity greater than 40 degrees (sp. gr. < 0.83) are ***light***.

Asphalt

Asphalt is a dark colored solid to semi-solid form of petroleum (at surface temperatures and pressures) that consists of heavy hydrocarbons and bitumens. It can occur naturally or as a residue in the refining of some petroleums. It generally contains appreciable amounts of sulphur, oxygen, and nitrogen and unlike kerogen, asphalt is soluble in normal petroleum solvents. It is produced by the partial maturation of kerogen or by the degradation of mature crude oil. Asphalt is particularly suitable for making high-quality gasoline and roofing and paving materials.

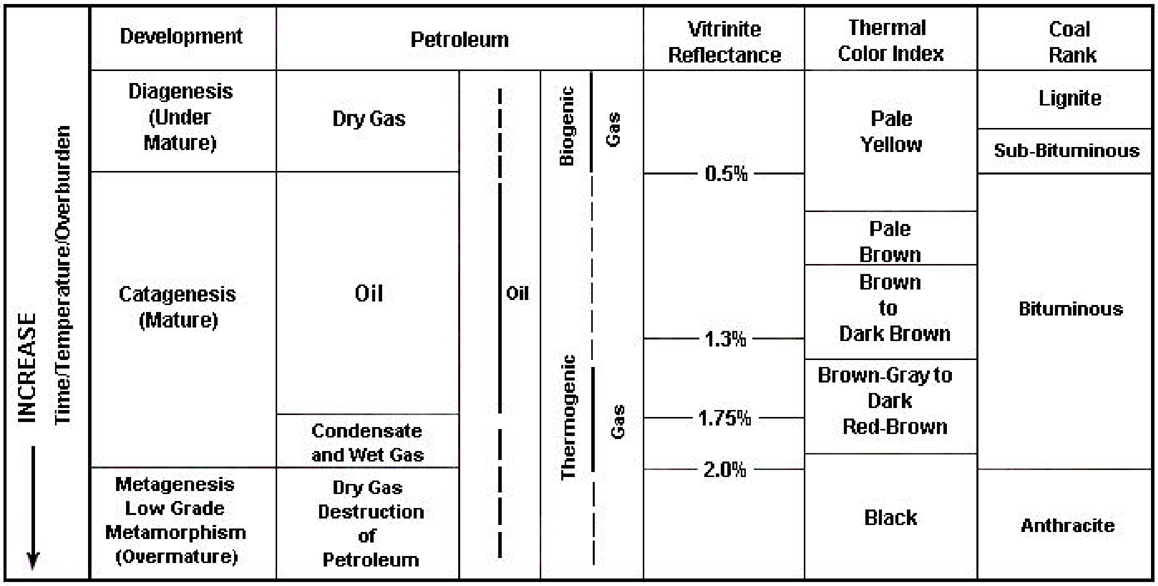
Natural Gas

There are two basic types of natural gas, biogenic gas and thermogenic gas. The difference between the two is contingent upon conditions of origin. **Biogenic gas** is a natural gas formed solely as a result of bacterial activity in the early stages of diagenesis, meaning it forms at low temperatures, at overburden depths of less than 3000 feet, and under anaerobic conditions often associated with high rates of marine sediment accumulation. Because of these factors, biogenic gas occurs in a variety of environments, including contemporary deltas of the Nile, Mississippi and Amazon rivers. Currently it is estimated that approximately 20% of the worlds known natural gas is biogenic. **Thermogenic gas** is a natural gas resulting from the thermal alteration of kerogen due to an increase in overburden pressure and temperature.

The major hydocarbon gases are: methane (CH_4), ethane (C_2H_6), propane (C_3H_8), and butane (C_4H_{10}).

The terms sweet and sour gas are used in the field to designate gases that are low or high, respectively, in hydrogen sulfide.

Natural gas, as it comes from the well, is also classified as dry gas or wet gas, according to the amount of natural gas liquid vapors it contains. A dry gas contains less than 0.1 gallon natural gas liquid vapors per 1,000 cubic feet, and a wet gas 0.3 or more liquid vapors per 1,000 cubic feet.



INCREASE Time/Temperature/Overburden	Development	Petroleum			Vitrinite Reflectance	Thermal Color Index	Coal Rank
	Diagenesis (Under Mature)	Dry Gas		Biogenic Gas		Pale Yellow	Lignite Sub-Bituminous
	Catagenesis (Mature)	Oil	Oil	Thermogenic Gas	0.5% 1.3%	Pale Brown Brown to Dark Brown	Bituminous
		Condensate and Wet Gas			1.75%	Brown-Gray to Dark Red-Brown	
	Metagenesis Low Grade Metamorphism (Overmature)	Dry Gas Destruction of Petroleum			2.0%	Black	Anthracite

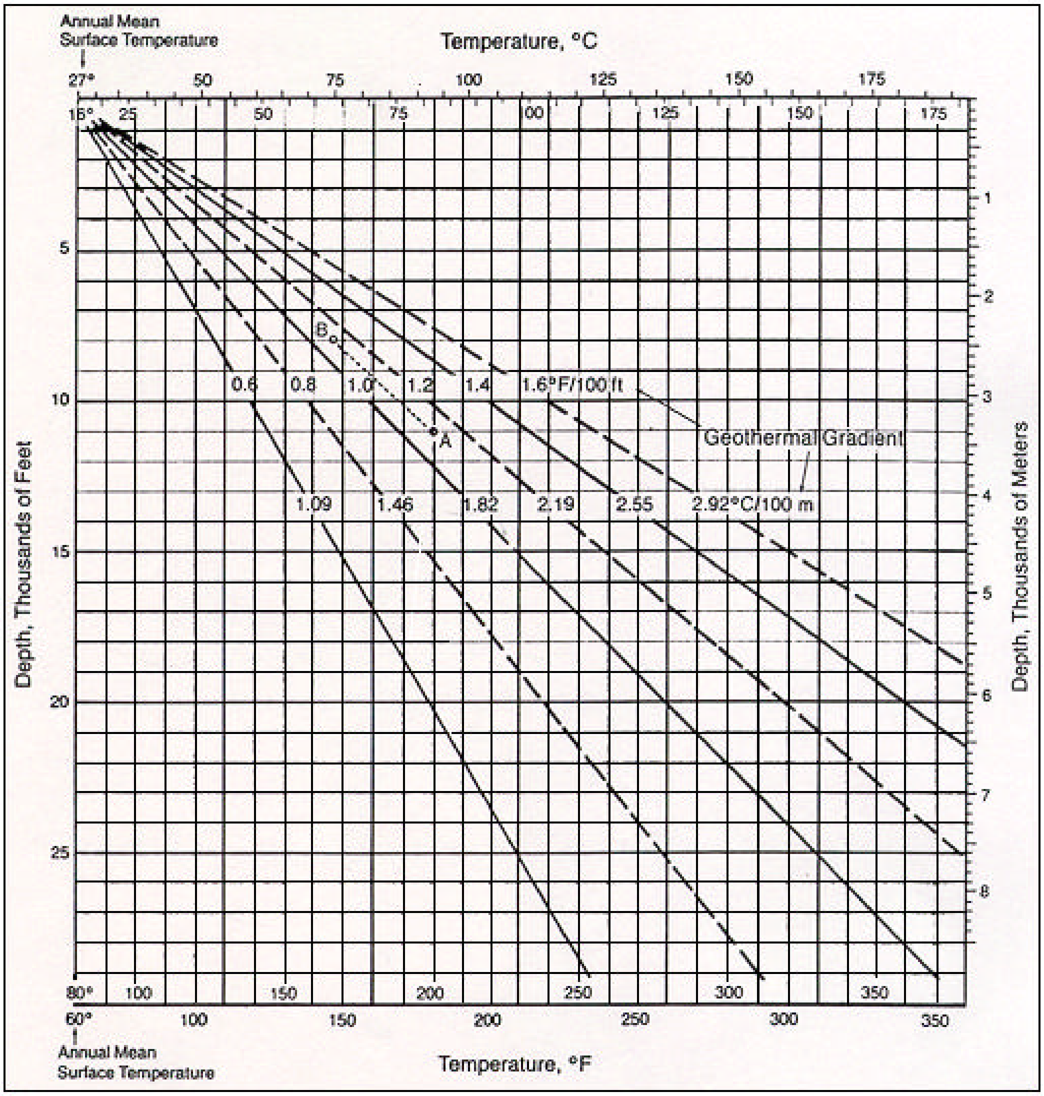
Figure 11 Thermal maturity indicators

Condensates

Condensates are hydrocarbons transitional between gas and crude oil (gaseous in the subsurface but condensing to liquid at surface temperatures and pressures). Chemically, condensates consist largely of paraffins, such as pentane, octane, and hexane.

Temperature Gradient

Temperature is generally a function of depth because of the earth's natural geothermal gradient. Normal heat flow within the earth's crust produces a gradient of approximately 1.5°F for each 100 feet of depth below the surface. The temperatures required to produce crude oil occur between 5,000 and 20,000 feet of depth. Temperatures below 20,000 feet are generally too high and only generate gas. Temperatures above 5,000 feet are not usually sufficient enough to transform the material into crude oil. There are, of course, exceptions to the rules. Geologic conditions such as volcanism and tectonics (folding and faulting) can change or effect the temperature gradient.



Graph 1 Temperature vs. Depth

Pressure Gradient

Most pressure that effects rocks is due to the weight of overlying rocks and is called **overburden pressure.** Overburden pressure is a function of depth and increases one pound per square inch for each foot of depth. At 3000 feet, for example, the overburden pressure would be 3,000 pounds per square inch. Hydrocarbons evolve from an immature stage to oil generation, oil cracking (wet gas stage), and finally to dry gas generation because of overburden pressure and the associated increase in temperature.

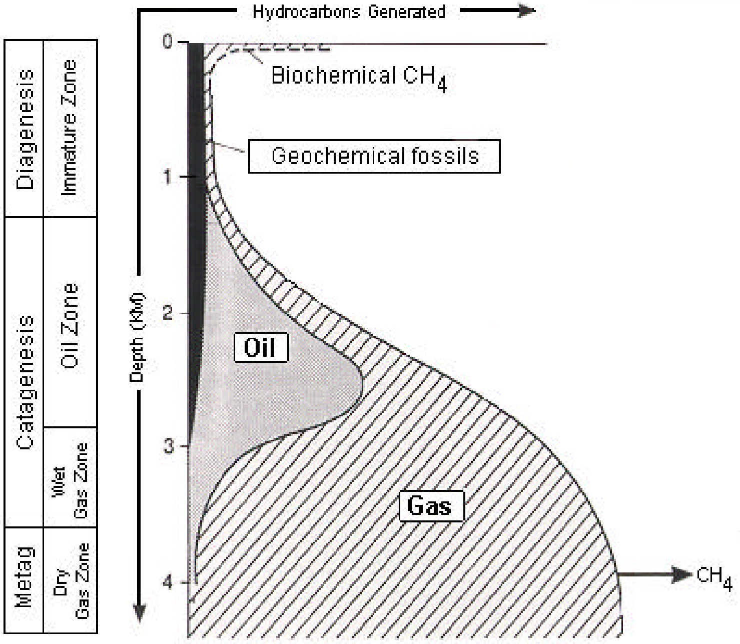
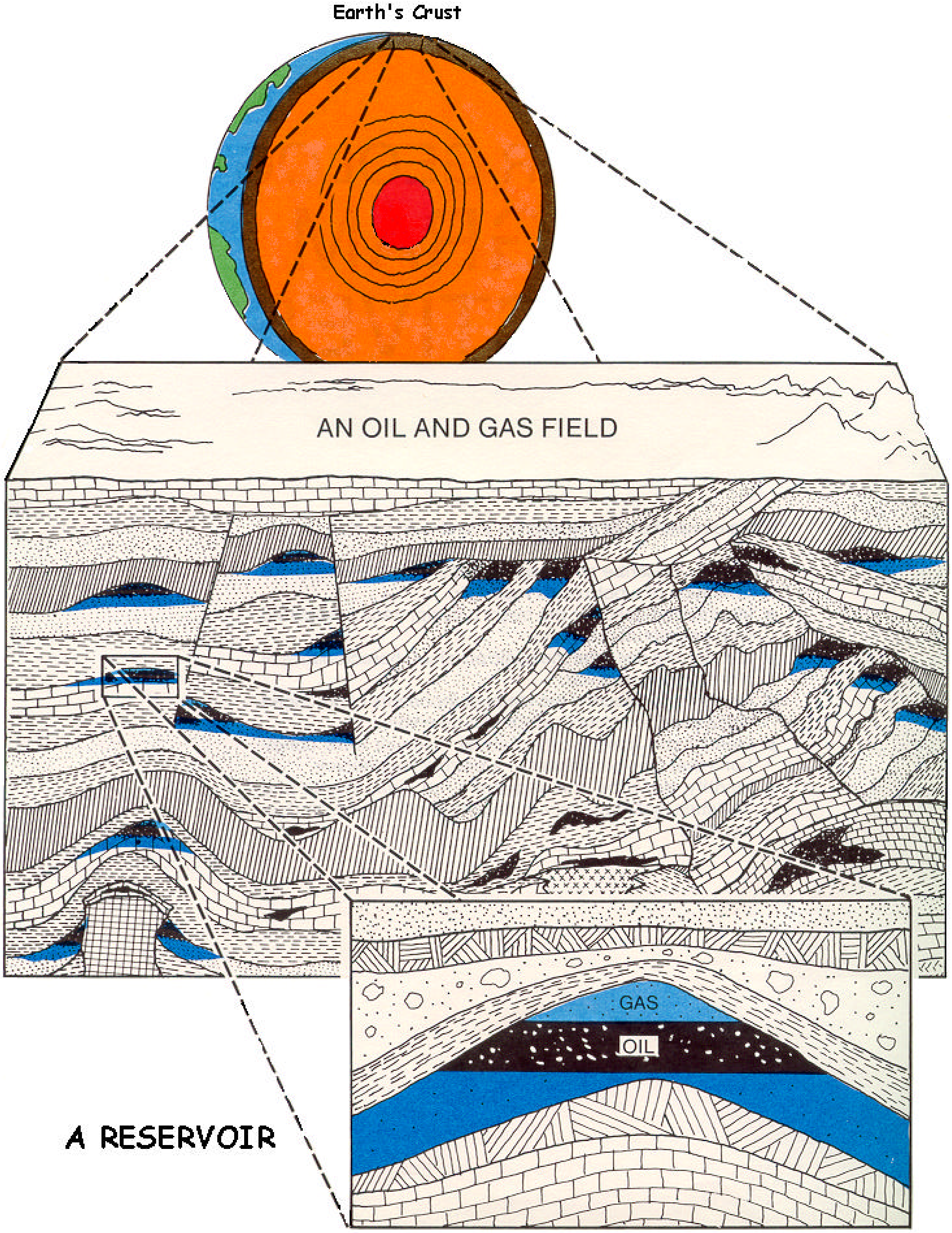


Figure 12 Hydrocarbon formation as a function of burial of the source rock

RESERVOIR GEOLOGY



What is a reservoir, and how does it develop over time?

A reservoir is a subsurface volume of porous and permeable rock that has both storage capacity and the ability to allow fluids to flow through it. Hydrocarbons migrate upward through porous and permeable rock formations until they either reach the surface as seepage or become trapped below the surface by a non-permeable cap rock which allows them to accumulate in place in the reservoir. Porosity and permeability are influenced by the depositional pore-geometries of the reservoir sediments and the post-depositional diagenetic changes that take place.

Sandstone reservoirs are generally created by the accumulation of large amounts of clastic sediments which is characteristic of depositional environments such as river channels, deltas, beaches, lakes and submarine fans. Sandstone reservoirs have a depositional porosity and permeability controlled by grain size, sorting, and packing of the particular sediments. Diagenetic changes may include precipitation of clay minerals in the pore space, occlusion of pores by mineral cements, or even creation of additional pores by dissolution of some sediments.

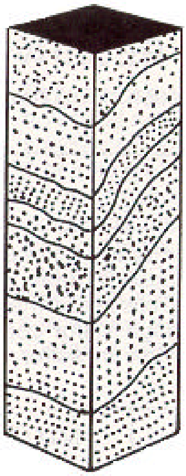


Figure 13

Carbonate reservoirs are created in marine sedimentary environments with little or no clastic material input and generally in a location between 30° north and south of the equator. Porosity types of carbonate reservoirs include vuggy (pores larger than grains), intergranular (between grains), intragranular or cellular (within grains), and chalky. Diagenetic changes such as dolomitization, fracturing, dissolution, and recrystalization (rare) are extremely important because they have the ability to create very effective secondary porosity. Cementation, another type of diagenesis, generally reduces porosity and permeability.

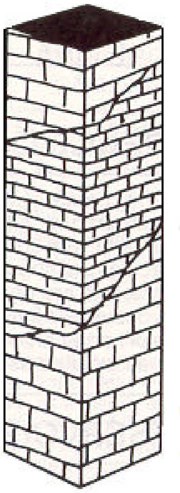


Figure 14

Abundance and Production of Sedimentary Formations

The approximate abundance and production for the three types of sedimentary formations significant to petroleum production are as follows:

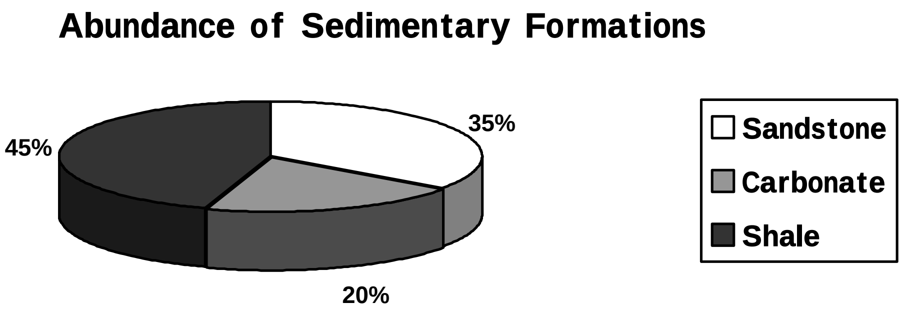


Chart 1

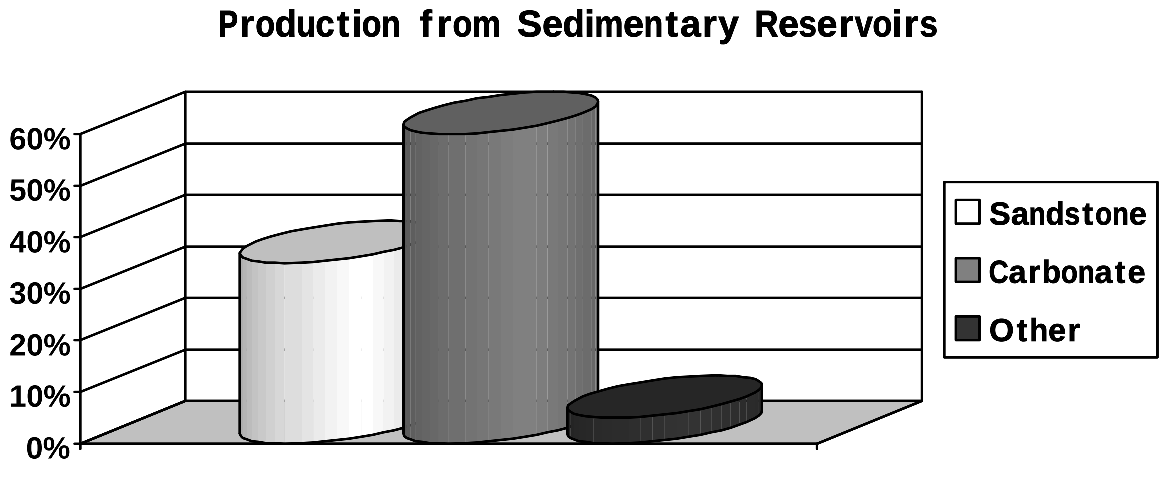


Chart 2

It is important to note that carbonate reservoirs produce almost twice the amount of hydrocarbons than sandstone reservoirs. This occurs because of substantial production from carbonate reservoirs in the Middle East and Mexico

Physical Characteristics of a Reservoir

Physical characteristics of a reservoir include original deposition and subsequent changes, the type of reservoir, sandstone or carbonate, which was discussed previously, depth, area, thickness, porosity, permeability, and capillary pressure.

Depth

The physical characteristics of a reservoir are greatly affected by the depth at which they occur.

Shallow reservoir— Created by the folding of relatively thick, moderately compacted reservoir rock with accumulation under an anticline or some trap. The hydrocarbons would generally be better separated as a result of lower internal reservoir pressures, less gas in solution and oil of increased viscosity, resulting from lower temperatures.

Deep reservoir— Typically created by severe faulting. The hydrocarbons would be less separated with more gas in solution and oil of reduced viscosity because of higher temperatures. There is often a reduction in porosity and permeability due to increased compaction.

Area and Thickness

The total area of a reservoir and its thickness are of considerable importance in determining if a reservoir is a commercial one or not. The greater the area and thickness of the reservoir, the greater the potential for large accumulations of oil and gas. However, there are reservoirs that produce substantial amounts of hydrocarbons that are not of considerable size.

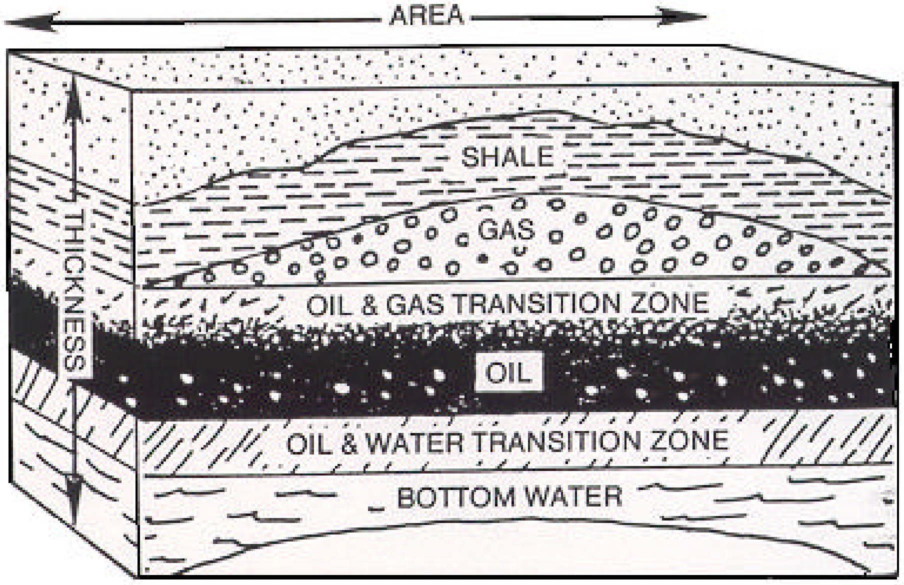


Figure 15

Porosity

Porosity is the ratio of void space in a rock to the total volume of rock, and reflects the fluid storage capacity of the reservoir.

$$\text{Porosity } (\Phi) = \frac{\text{volume of void space}}{\text{total volume of rock}}$$

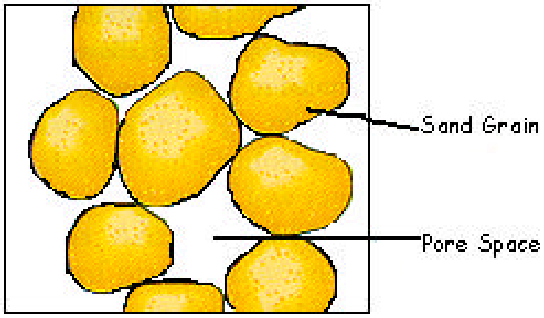


Figure 16 Porous sandstone.

Porosity is expressed as a percentage on a log. When used in calculations, however, it is important that porosity be expressed in decimal form.

- **Primary Porosity**— Amount of pore space present in the sediment at the time of deposition, or formed during sedimentation. It is usually a function of the amount of space between rock-forming grains.
    - **Secondary Porosity**— Post depositional porosity. Such porosity results from groundwater dissolution, recrystallization and fracturing.
    - **Effective Porosity vs. Total Porosity—** Effective porosity is the interconnected pore volume available to free fluids. Total porosity is all void space in a rock and matrix whether effective or noneffective.

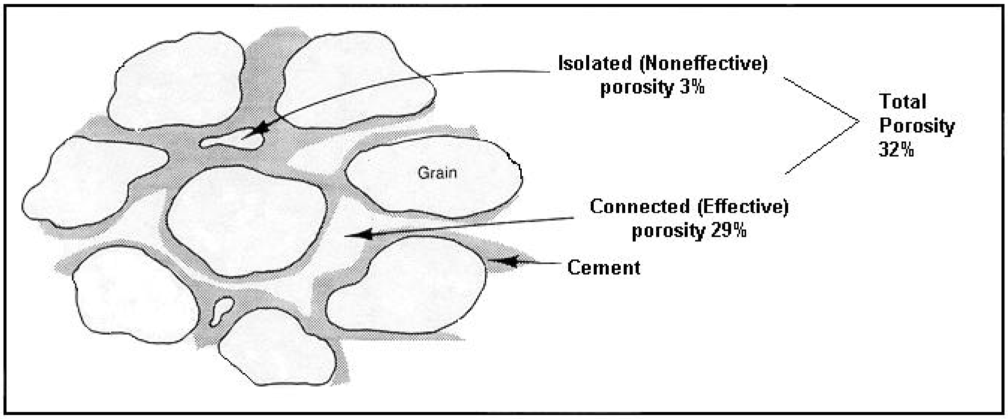


Figure 17 Effective vs. noneffective porosity

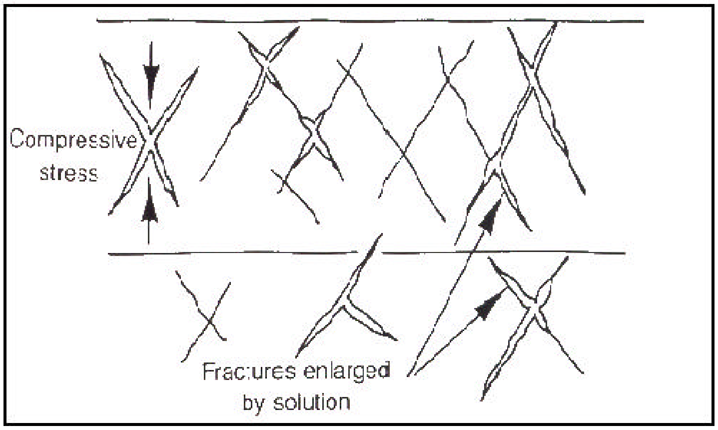


Figure 18 Fractures in rock material

- **Fracture porosity** results from the presence of openings produced by the breaking or shattering of a rock. All rock types are affected by fracturing and a rocks composition will determine how brittle the rock is and how much fracturing will occur. The two basic types of fractures include natural tectonically related fractures and hydraulically induced fractures. ***Hydraulic fracturing*** is a method of stimulating production by inducing fractures and fissures in the formation by injecting fluids into the reservoir rock at pressures which exceed the strength of the rock. Hydraulic fracturing can tremendously increase the effective porosity and permeability of a formation

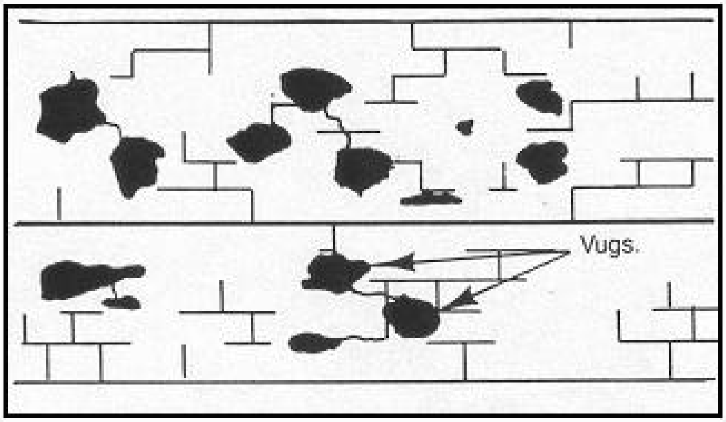


Figure 19 Vuggy porosity in carbonates

- **Vuggy porosity** is a form of secondary porosity resulting from the dissolution of the more soluble portions of rock or solution enlargement of pores or fractures.

- **Maximum Porosity vs. Realistic Porosity**— Porosity can approach, in a very well sorted uncompacted sand, a theoretical maximum of 47.6%. In a sandstone, this value is typically much lower due to cementation and compaction. In a carbonate, it is possible to greatly exceed the theoretical maximum porosity. This may be achieved if the carbonate is highly fractured along with vuggy porosity.

Controls on Porosity

In sandstone, porosity is largely controlled by sorting. Sorting is a process by which the agents of transportation, especially running water, naturally separate sedimentary particles that have some particular characteristic (such as size, shape or specific gravity) from associated but dissimilar particles. Other important controlling factors include grain packing, compaction, and cementation.

- **Well Sorted Rock**— Grains are generally of the same size and shape. If the grains are well rounded and of similar size, then they will not fit well together, thereby leaving a large amount of pore space between the grains. Porosity in a well sorted rock is generally high.

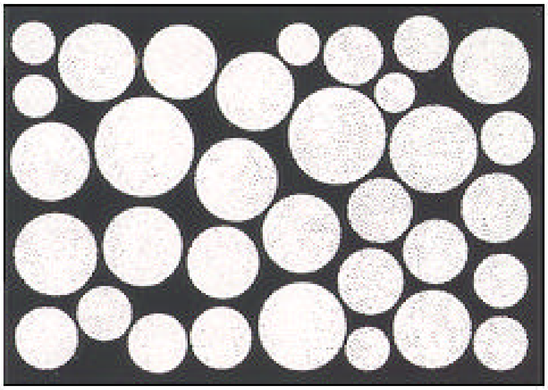


Figure 20 Very well sorted

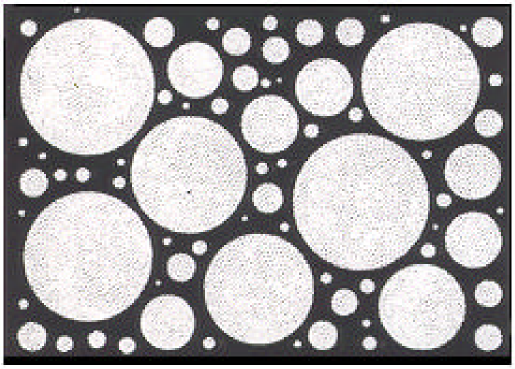


Figure 21 Poorly sorted

- **Poorly Sorted Rock**— Rock that is composed of a wide variety of grain sizes and shapes. Porosity can be reduced considerably because smaller or irregularly shaped grains can be inserted in between the larger grains, thereby reducing the amount of pore space.

- **Grain Packing**— Refers to the spacing or density patterns of grains in a sedimentary rock and is a function mainly of grain size, grain shape, and the degree of compaction of the sediment.

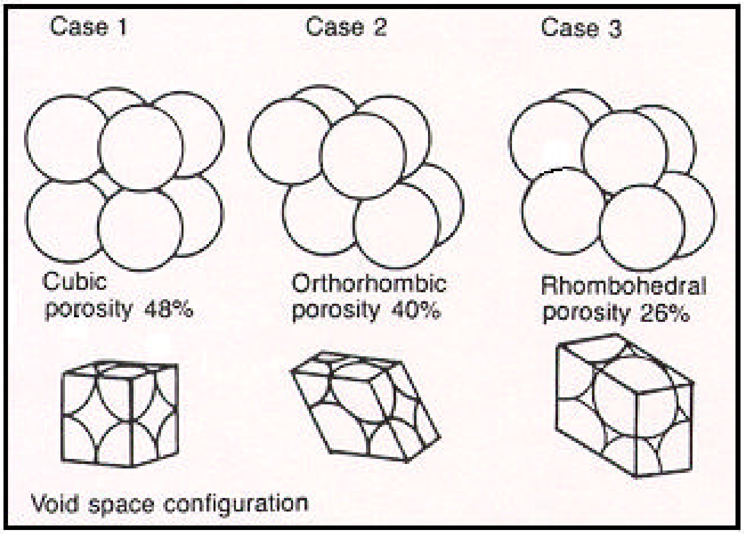


Figure 22 Grain packing and its effect on porosity

Packing strongly affects the bulk density of the rocks as well as their porosity and permeability. The effects of packing on porosity can be illustrated by considering the change in porosity that takes place when even-size spheres are rearranged from open packing (cubic packing) to tightest or closed packing (rhombohedral packing).

Cubic packing can yield a porosity of 47.6%. Rhombohedral packing yields approximately 26.0%.

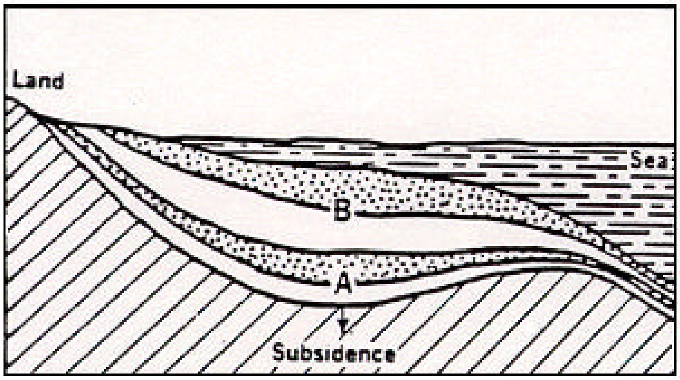


Figure 23I Sedimentation process: Layer A is compacted by layer B

- **Compaction** — Over a long period of time sediments can accumulate and create formations that are thousands of feet thick. The weight of the overlying sediments squeezes the particles together into the tightest arrangement possible. The load pressure also squeezes out the water that occupies the pore spaces between the particles, thus reducing the bulk volume of the formation. Compaction is dependent not only on overburden pressure but also on the different types of clastic materials present in the formation. Compaction affects porosity and permeability by reducing the amount of interconnected pore space.

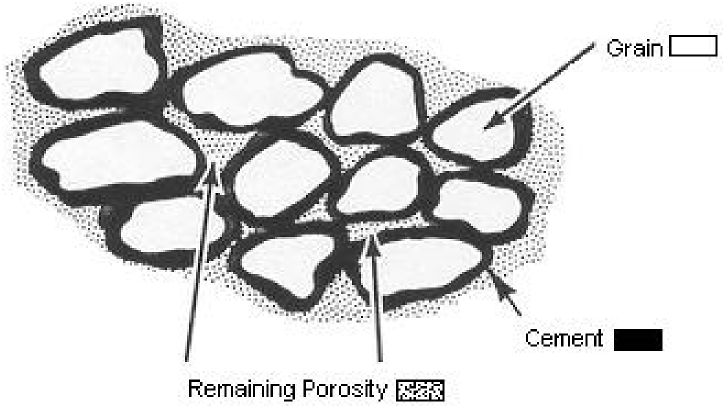


Figure 24 Effect of cementation on porosity

- **Cementation** — Cementation is the crystallization or precipitation of soluble minerals in the pore spaces between clastic particles. The process of lithification (the conversion of unconsolidated deposits into solid rock) is completed by cementation. Common cementing agents include calcite ($CaCO_3$), silica (SiO_2), and iron oxide (Fe_2O_3). Minerals in solution crystallize out of solution to coat grains and may eventually fill the pore spaces completely. Porosity and permeability can be reduced significantly due to cementation.

Permeability

Recovery of hydrocarbons from the reservoir is an important process in petroleum engineering and estimating permeability can aid in determining how much hydrocarbons can be produced from a reservoir. Permeability is a measure of the ease with which a formation permits a fluid to flow through it. To be permeable, a formation must have interconnected porosity (intergranular or intercrystalline porosity, interconnected vugs, or fractures).

To determine the permeability of a formation, several factors must be known: the size and shape of the formation, its fluid properties, the pressure exerted on the fluids, and the amount of fluid flow. The more pressure exerted on a fluid, the higher the flow rate. The more viscous the fluid, the more difficult it is to push through the rock. **Viscosity** refers to a fluid's internal resistance to flow, or it's internal friction. For example, it is much more difficult to push honey through a rock than it is to push air through it.

Permeability is measured in darcies. Few rocks have a permeability of 1 darcy, therefore permeability is usually expressed in millidarcies or 1/1000 of a darcy.

Permeability is usually measured parallel to the bedding planes of the reservoir rock and is commonly referred to as horizontal permeability. This is generally the main path of the flowing fluids into the borehole. Vertical permeability is measured across the bedding planes and is usually less than horizontal permeability. The reason why horizontal permeability is generally higher than vertical permeability lies largely in the arrangement and packing of the rock grains during deposition and subsequent compaction. For example, flat grains may align and overlap parallel to the depositional surface, thereby increasing the horizontal permeability, see Figure 25. High vertical permeabilities are generally the result of fractures and of solution along the fractures that cut across the bedding planes. They are commonly found in carbonate rocks or other rock types with a brittle fabric and also in clastic rocks with a high content of soluble material. As seen in Figure 25, high vertical permeability may also be characteristic of uncemented or loosely packed sandstones.

Examples of variations in permeability and porosity

- Some fine-grained sandstones can have large amounts of interconnected porosity; however, the individual pores may be quite small. As a result, the pore throats connecting individual pores may be quite restricted and tortuous; therefore, the permeabilities of such fine-grained formations may be quite low.
- Shales and clays— which contain very fine-grained particles— often exhibit very high porosities. However, because the pores and pore throats within these formations are so small, most shales and clays exhibit virtually no permeability.
- Some limestones may contain very little porosity, or isolated vuggy porosity that is not interconnected. These types of formations will exhibit very little permeability. However, if the formation is naturally fractured (or even hydraulically fractured), permeability will be higher because the isolated pores are interconnected by the fractures.

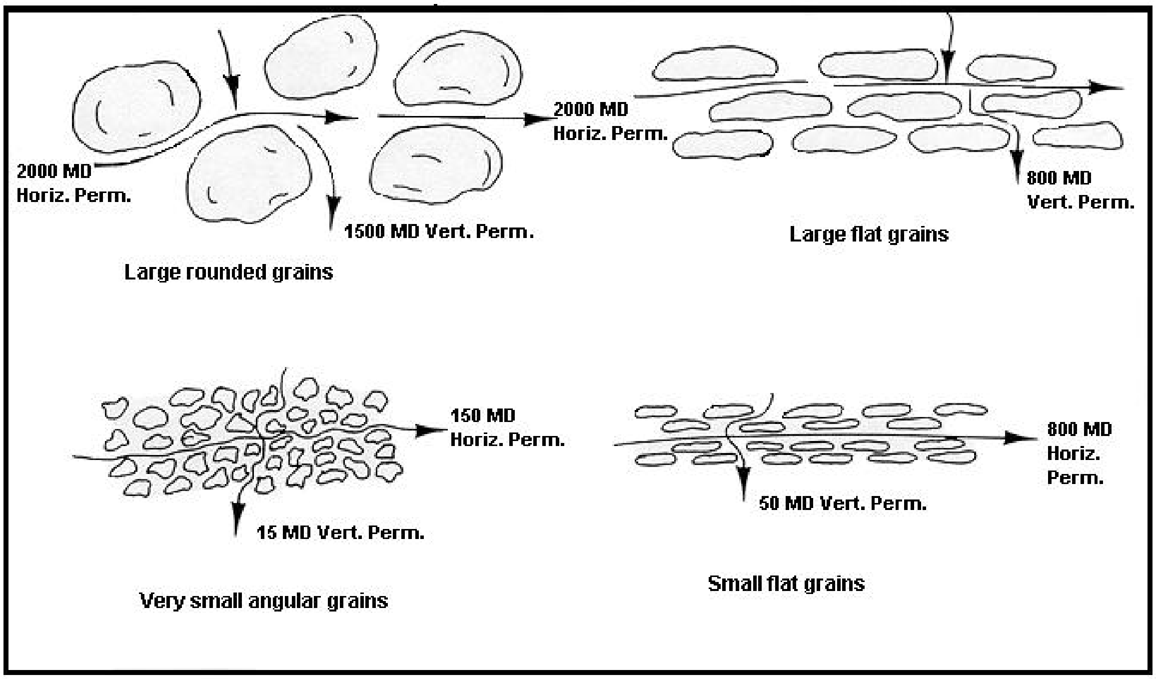


Figure 25 Permeability and grain size and shape

- **POROSITY IS NOT DEPENDENT ON GRAIN SIZE**
- **PERMEABILITY IS DEPENDENT ON GRAIN SIZE**

Fluid Distribution within a Reservoir

Petroleum reservoirs generally contain a combination of three fluids:

1). Natural Gas

2). Oil

3). Water

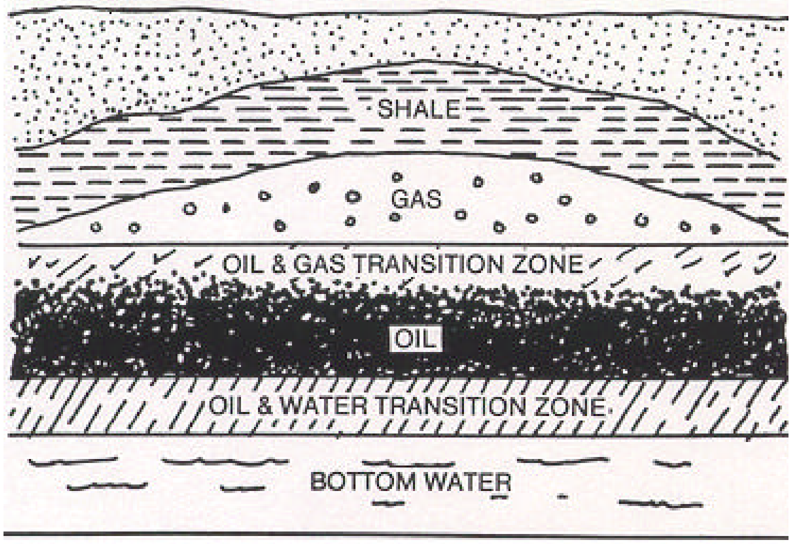


Figure 26

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.**

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. 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. 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.

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 27, 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 contractile force is called **surface tension.** The top layer of molecules acts much like a membrane of

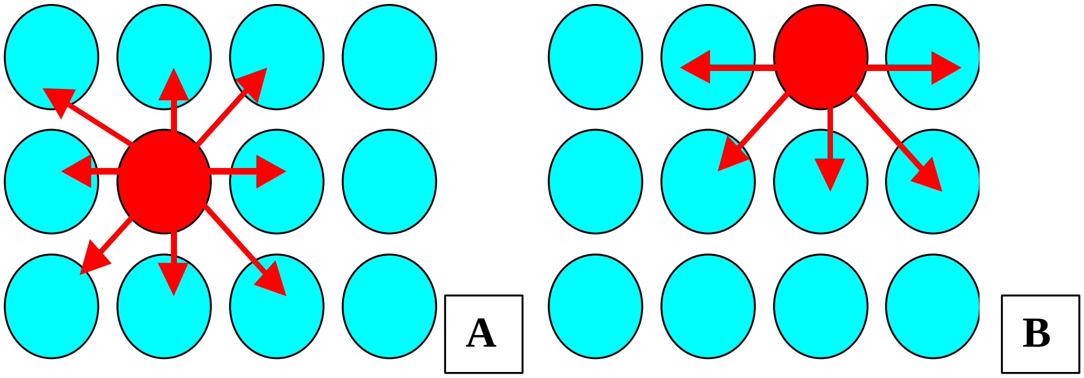


Figure 27 The principle of surface tension

rubber, 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. 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, see Figure 28. 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.**

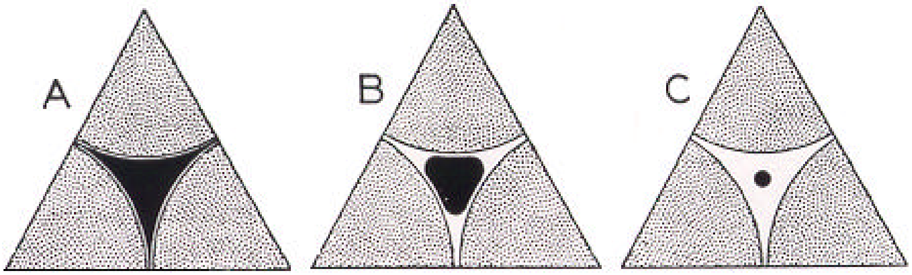


Figure 28 Distribution of nonwetting oil (black) in a single water-wet pore (water blank/white).

Capillary Pressure

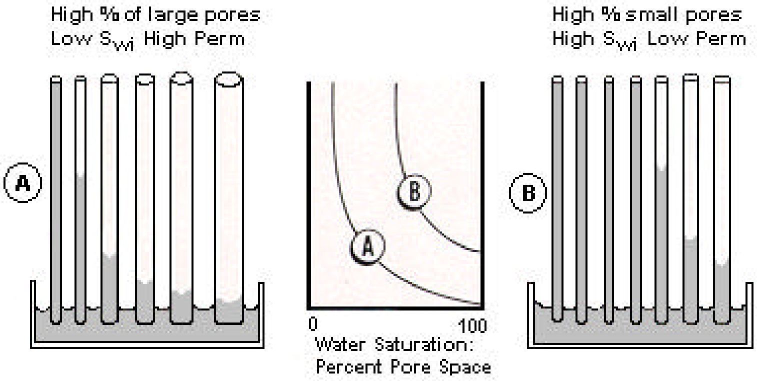


Figure 30 Capillary pressure effects in reservoirs

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 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 30 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 30 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 adhesion of 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.

Large pore throat diameters

- Generally yield a lower capillary pressure because of the decrease in the amount of surface tension.
- Large pores that are often associated with large pore throat diameters will also contain lesser amounts of adsorbed (adhered) water because the surface-to-volume ratio of the pore is low.

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 surface-to-volume ratio, and therefore may contain greater amounts of adsorbed (adhered) water.

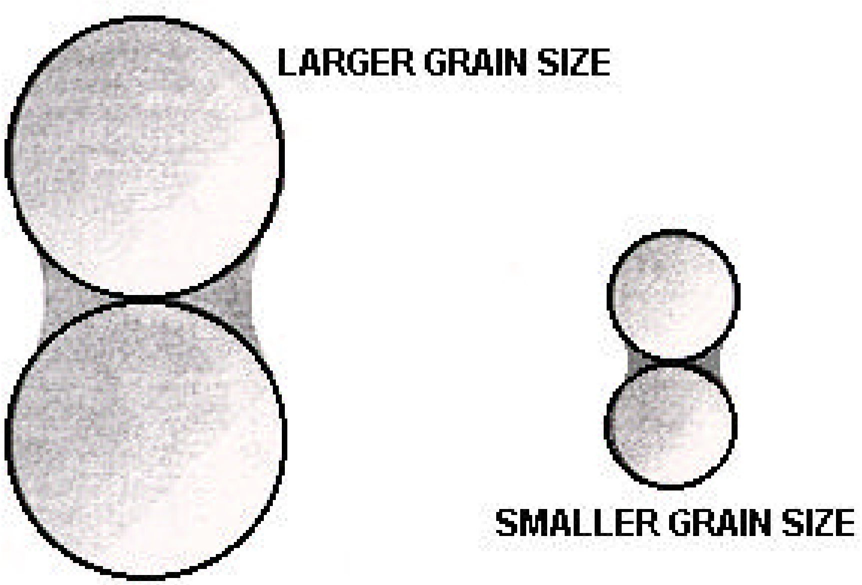


Figure 31 Grain size effects on capillary pressure and pore throat diameters.

Irreducible Water Saturation

As previously stated, all sedimentary rocks have porosity that is fluid saturated. The fluid is sometimes oil and/or gas, but water is always present. **Water saturation** is defined as the fraction of that porosity that is occupied by water. If the pore space is not occupied by water, then it must be occupied by hydrocarbons. Therefore, by determining a value of water saturation from porosity and resistivity measurements, it is possible to determine the fraction of pore space that is occupied by hydrocarbons (**hydrocarbon saturation**).

Water saturation simply refers to the *amount* of water that is present in the reservoir, and says nothing about its *ability to be produced*. In a reservoir containing a small amount of water, it might be possible to produce this water if capillary pressures are low and the water is not adsorbed (adhered) onto the surfaces of rock grains. However, if this water is adhered to the surfaces of rock grains and there is a high capillary pressure, then it is possible to produce water-free hydrocarbons from a reservoir that does contain some water.

For any reservoir, there is a certain value of water saturation at which all of the contained water will be trapped by capillary pressure and/or by adsorption of water on the surface of rock grains (surface tension). This is referred to as **irreducible water saturation (S_{wirr}).** At irreducible water saturation, all of the water within the reservoir will be immovable, and hydrocarbon production will be water-free.

Basic Geological Conditions That Create Petroleum Traps

Hydrocarbon traps are any combination of physical factors that promote the accumulation and retention of petroleum in one location. Traps can be structural, stratigraphic, or a combination of the two.

Geologic processes such as faulting, folding, piercement, and deposition and erosion create irregularities in the subsurface strata which may cause oil and gas to be retained in a porous formation, thereby creating a petroleum reservoir. The rocks that form the barrier, or trap, are referred to as caprocks.

Structural Traps

Structural traps are created by the deformation of rock strata within the earth's crust. This deformation can be caused by horizontal compression or tension, vertical movement and differential compaction, which results in the folding, tilting and faulting within sedimentary rock formations.

- **Anticlinal and Dome Trap—** 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.

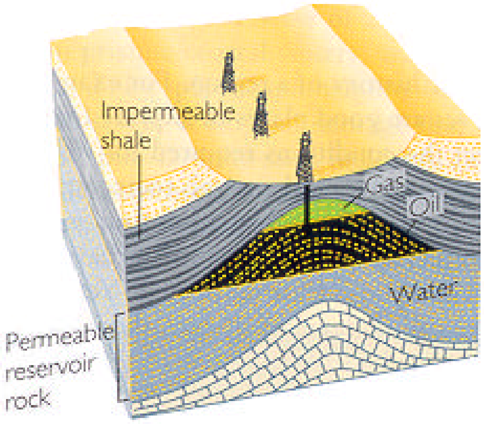


Figure 32 Anticlinal Trap

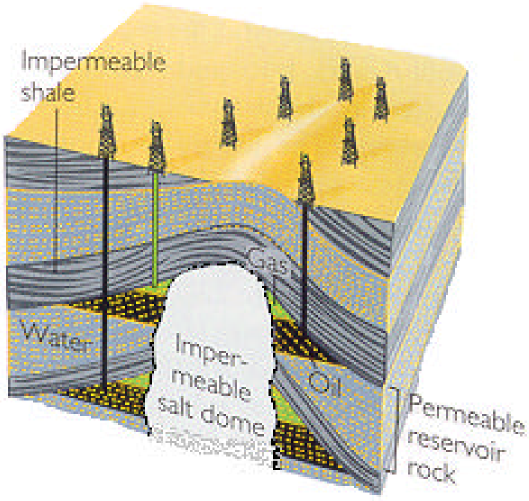


Figure 33 Salt Dome Trap

- **Salt Dome or Salt Plug Trap**— A trap created by piercement or intrusion of stratified rock layers from below by ductile nonporous salt. The intrusion causes the lower formations nearest the intrusion to be uplifted and truncated along the sides of the intrusion, while layers above are uplifted creating a dome or anticlinal folding. Hydrocarbons migrate into the porous and permeable beds on the sides of the column of salt. Hydrocarbons accumulate in the traps around the outside of the salt plug if a seal or cap rock is present.

- **Fault Trap**— The faulting of stratified rock occurs as a result of vertical and horizontal stress. At some point the rock layers break, resulting in the rock faces along the fracture moving or slipping past each other into an offset position. A fault trap is formed when the faulted formations are tilted toward the vertical. When a non-porous rock face is moved into a position above and opposite a porous rock face, it seals off the natural flow of the hydrocarbons allowing them to accumulate.

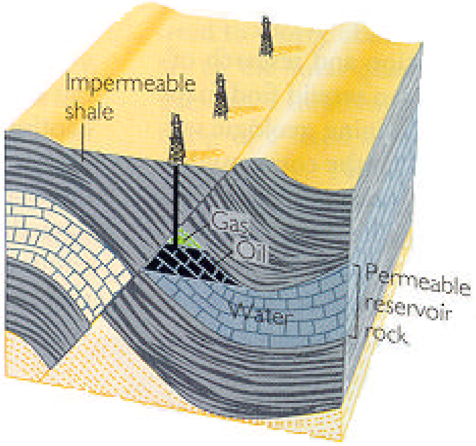


Figure 34 Fault Trap

Figure 35 Faulting

Figure 36 Folding

Stratigraphic Traps

Stratigraphic traps are formed as a result of differences or variations between or within stratified rock layers, creating a change or loss of permeability from one area to another. These traps do not occur as a result of movement of the strata.

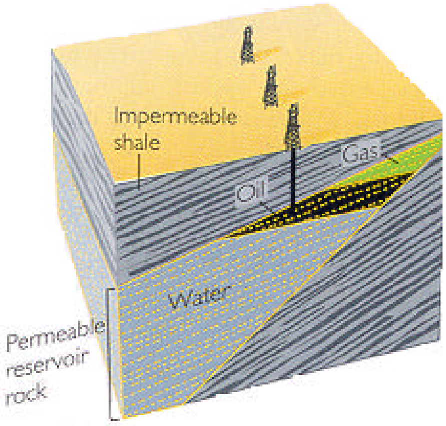


Figure 37 Stratigraphic Trap

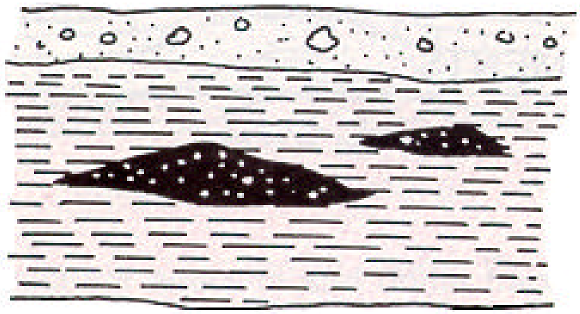


Figure 38 Lens trap

- **Lenticular trap—** A porous area surrounded by non-porous strata. They may be formed from ancient buried river sand bars, beaches, etc.

- **Pinch-out or lateral graded trap—** A trap created by lateral differential deposition when the environmental deposition changes up-dip.

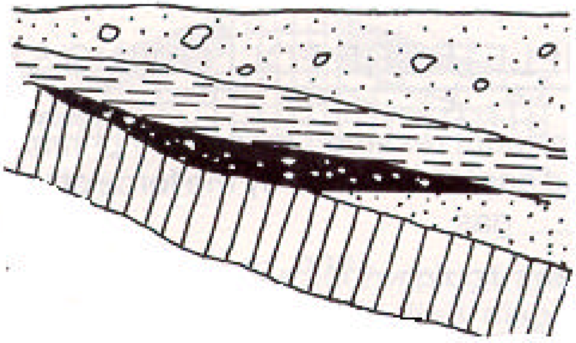


Figure 39 Pinch-out trap

Angular Unconformtiy Trap— An angular unconformity is one in which older strata dips at an angle different from that of younger strata.

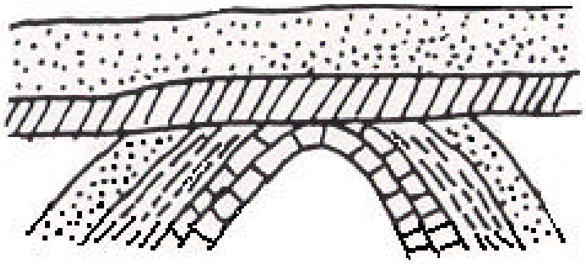


Figure 40 Eroded anticline

An angular unconformity trap occurs when inclined, older petroleum bearing rocks are subjected to the forces of younger non-porous formations. This condition may occur whenever an anticline, dome or monocline are eroded and then overlain with younger, less permeable strata.

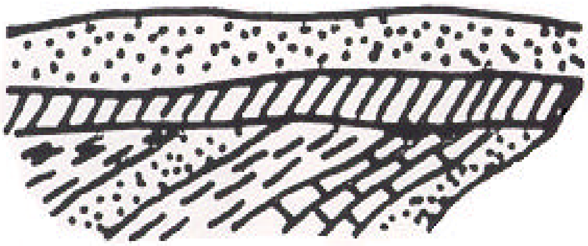


Figure 41 Eroded monocline

Figure 42 Angular unconformity

Exploration and Mapping Techniques

Exploration for oil and gas has long been considered an art as well as a science. It encompasses a number of older methods in addition to new techniques. The explorationist must combine scientific analysis and an imagination to successfully solve the problem of finding and recovering hydrocarbons.

Subsurface Mapping

Geologic maps are a representation of the distribution of rocks and other geologic materials of different lithologies and ages over the Earth's surface or below it. The geologist measures and describes the rock sections and plots the different formations on a map, which shows their distribution. Just as a surface relief map shows the presence of mountains and valleys, **subsurface mapping** is a valuable tool for locating underground features that may form traps or outline the boundaries of a possible reservoir. Once a reservoir has been discovered, it is also the job of the geologist to present enough evidence to support the development and production of that reservoir.

Subsurface mapping is used to work out the geology of petroleum deposits. Three-dimensional subsurface mapping is made possible by the use of well data and helps to decipher the underground geology of a large area where there are no outcrops at the surface.

Some of the commonly prepared subsurface geological maps used for exploration and production include; (1) geophysical surveys, (2) structural maps and sections, (3) isopach maps, and (4) lithofacies maps.

Geophysical Surveys

Geophysics is the study of the earth by quantitative physical methods. Geophysical techniques such as seismic surveys, gravity surveys, and magnetic surveys provide a way of measuring the physical properties of a subsurface formation. These measurements are translated into geologic data such as structure, stratigraphy, depth, and position. The practical value in geophysical surveys is in their ability to measure the physical properties of rocks that are related to potential traps in reservoir rocks as well as documenting regional structural trends and overall basin geometry.

Seismic Surveys

The geophysical method that provides the most detailed picture of subsurface geology is the seismic survey. This involves the natural or artificial generation and propagation of seismic (elastic) waves down into Earth until they encounter a discontinuity (any interruption in sedimentation) and are reflected back to the surface. On-land, seismic "shooting" produces acoustic waves at or near the surface by energy sources such as dynamite, a “Thumper” (a weight dropped on ground surface), a “Dinoseis” (a gas gun), or a “Vibroseis” (which literally vibrates the earth’s surface).

Electronic detectors called geophones then pick up the reflected acoustic waves. The signal from the detector is then amplified, filtered to remove excess “noise”, digitized, and then transmitted to a nearby truck to be recorded on magnetic tape or disk.

In the early days of offshore exploration, explosive charges suspended from floats were used to generate the necessary sound waves. This method is now banned in many parts of the world because of environmental considerations. One of the most common ways to generate acoustic waves today is an air gun. Air guns contain chambers of compressed gas. When the gas is released under water, it makes a loud “pop” and the seismic waves travel through the rock layers until they are reflected back to the surface where they are picked up by hydrophones, the marine version of geophones, which trail behind the boat.

The data recorded on magnetic tape or disk can be displayed in a number of forms for interpretation and research purposes; including visual display forms (photographic and dry-paper), a display of the amplitude of arriving seismic waves versus their arrival time, and a common type of display called variable-density. The variable-density display is generated by a technique in which light intensity is varied to enhance the different wave amplitudes. For example, low amplitude waves are unshaded and higher amplitude waves are shaded black, thus strong reflections will show up as a black line on the display.

Seismic waves travel at known but varying velocities depending upon the kinds of rocks through which they pass and their depth below Earth’s surface. The speed of sound waves through the earth’s crust varies directly with density and inversely with porosity. Through soil, the pulses travel as slowly as 1,000 feet per second, which is comparable to the speed of sound through air at sea level. On the other hand, some metamorphic rocks transmit seismic waves at 20,000 feet (approximately 6 km) per second, or slightly less than 4 miles per second. Some typical average velocities are: shale = 3.6 km/s; sandstone = 4.2 km/s; limestone = 5.0 km/s. If the subsurface lithology is relatively well known from drilling information, it is possible to calculate the amount of time it takes a wave to travel down through the earth to a discontinuity and back to the surface. This information is used to compute the depth of the discontinuity or unconformity. However, the only way of accurately determining depth is by correlating seismic sections to wireline logs. Reflections are generated at unconformities because unconformities separate rocks having different structural attitudes or physical properties, particularly different lithologies. These principles form the basis for application of seismic methods to geologic study.

Magnetic Surveys

Magnetic surveys are methods that provide the quickest and least expensive way to study *gross* subsurface geology over a broad area. A magnetometer is used to measure local variations in the strength of the earth’s magnetic field and, indirectly, the thickness of sedimentary rock layers where oil and gas might be found. Igneous and metamorphic rocks usually contain some amount of magnetically susceptible iron-bearing minerals and are frequently found as basement rock that lies beneath sedimentary rock layers. Basement rock seldom contains hydrocarbons, but it sometimes intrudes into the overlying sedimentary rock, creating structures such as folds and arches or anticlines that could serve as hydrocarbon traps. Geophysicists can get a fairly good picture of the configuration of the geological formations by studying the anomalies, or irregularities, in the structures.

The earth’s magnetic field, although more complex, can be thought of as a bar magnet, around which the lines of magnetic force form smooth, evenly spaced curves. If a small piece of iron or titanium is placed within the bar magnet’s field it becomes weakly magnetized, creating an anomaly or distortion of the field. The degree to which igneous rocks concentrate this field is not only dependent upon the amount of iron or titanium present but also upon the depth of the rock. An igneous rock formation 1,000 feet below the surface will affect a magnetometer more strongly than a similar mass 10,000 feet down. Thus, a relatively low magnetic field strength would indicate an area with the thickest sequence of nonmagnetic sedimentary rock. Once the magnetic readings have been plotted on a map, points of equal field strength are connected by contour lines, thus creating a map that is the rough equivalent to a topographic map of the basement rock. This can be useful in locating basic geologic structures, although it will not reveal details of the structures or stratigraphy.

Gravity Surveys

The gravity survey method makes use of the earth’s gravitational field to determine the presence of gravity anomalies (abnormally high or low gravity values) which can be related to the presence of dense igneous or metamorphic rock or light sedimentary rock in the subsurface. Dense igneous or metamorphic basement rocks close to the surface will read much higher on a gravimeter because the gravitational force they exert is more powerful than the lighter sedimentary rocks. The difference in mass for equal volumes of rock is due to variations in specific gravity.

Although mechanically simple, a gravimeter can measure gravity anomalies as small as one billionth of the earth’s surface gravity. Data collected from gravity surveys can be used to construct contour maps showing large-scale structures and, like magnetic survey contour maps, smaller details will not be revealed.

Geophysicists applied this knowledge, particularly in the early days of prospecting off the Gulf of Mexico. Often, they could locate salt domes using data from a gravity survey because ordinary domal and anticlinal structures are associated with maximum gravity, whereas salt domes are usually associated with minimum gravity.

Structural Contour Maps

Contour maps show a series of lines drawn at regular intervals. The points on each line represent equal values, such as depth or thickness. One type of contour map is the structural map, which depicts the depth of a specific formation from the surface. The principle is the same as that used in a topographic map, but instead shows the highs and lows of the buried layers.

Contour maps for exploration may depict geologic structure as well as thickness of formations. They can show the angle of a fault and where it intersects with formations and other faults, as well as where formations taper off or stop abruptly. The subsurface structural contour map is almost or fully dependent on well data for basic control

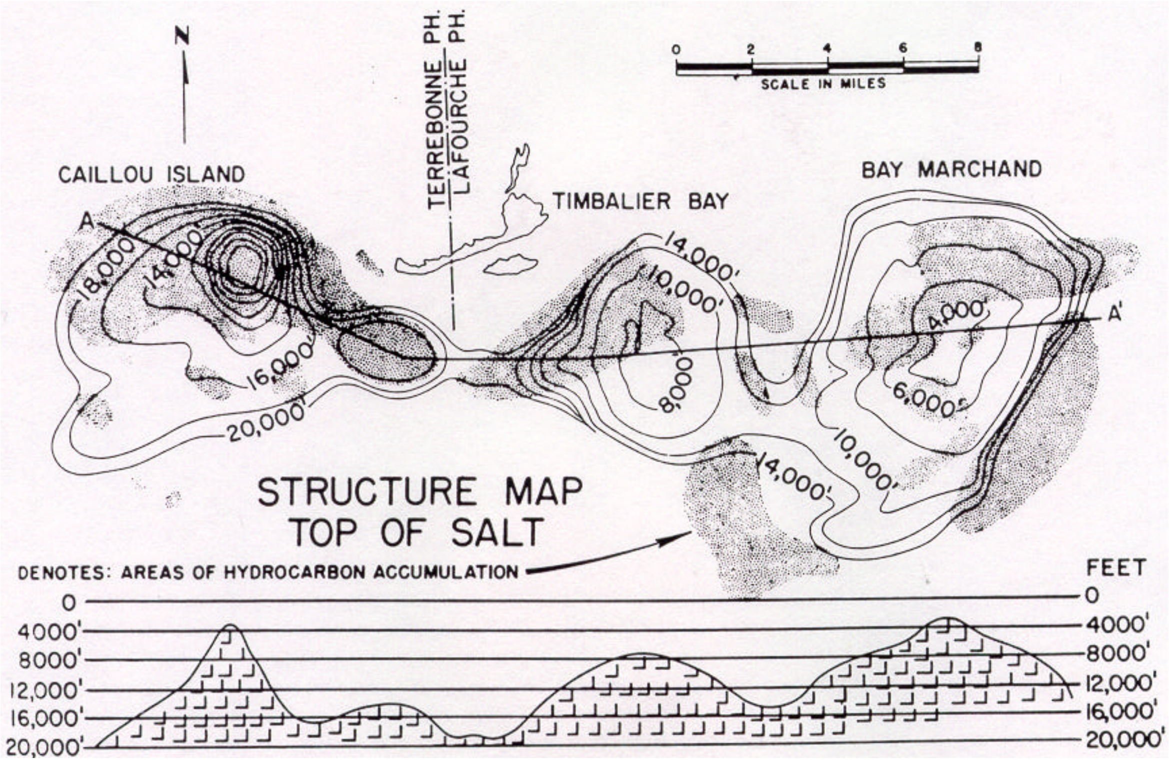


Figure 43 Structural map and longitudinal profile section showing top of salt, which is datum for structure contours

Cross-Sections

Structural, stratigraphic, and topographic information can be portrayed on cross-sections that reproduce horizontally represented map information in vertical section. Maps represent information in the plan view and provide a graphic view of distribution. Cross-sections present the same information in the vertical view and illustrate vertical relationships such as depth, thickness, superpostion, and lateral and vertical changes of geologic features.

Raw data for cross-sections come from stratigraphic sections, structural data, well sample logs, cores, wireline logs, and structural, stratigraphic, and topographic maps.

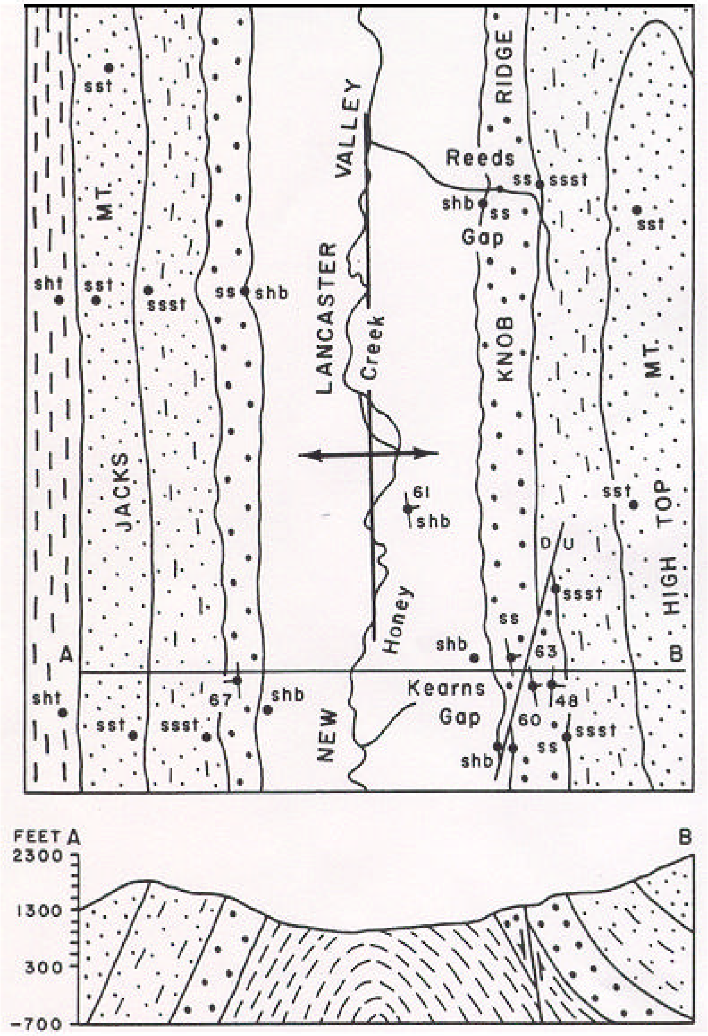


Figure 44 Completed geologic map and cross-section

Isopach Maps

Isopach maps are similar in appearance to contour maps but show variations in the thickness of the bed. These maps may be either surface or subsurface depending on data used during construction. Isopach maps are frequently color coded to assist visualization and are very useful in following pinchouts or the courses of ancient stream beds. Porosity or permeability variations may also be followed by such means. Geologists use isopach maps to aid in exploration work, to calculate how much petroleum remains in a formation, and to plan ways to recover it.

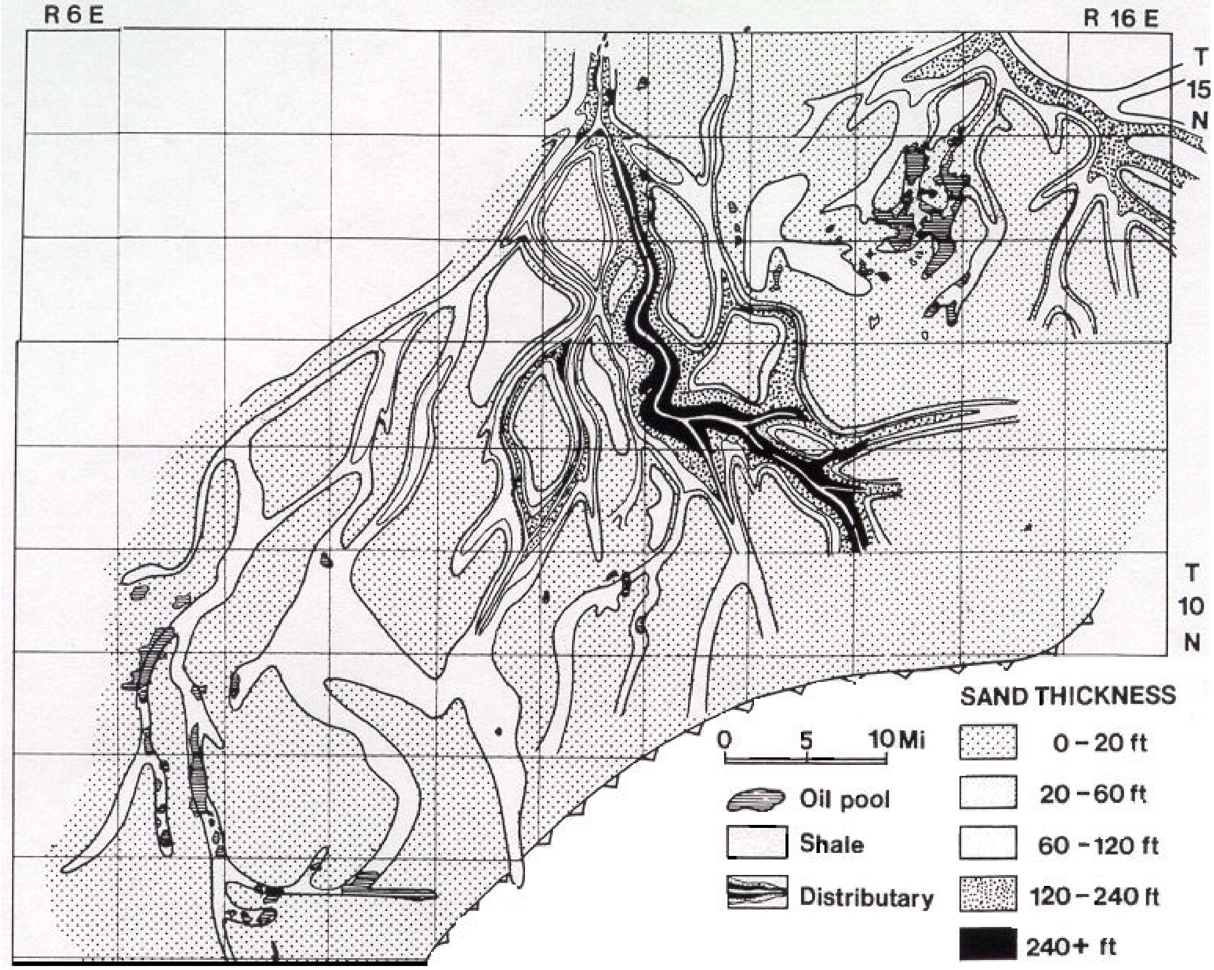


Figure 45 Isopach map of channel sandstone

Lithofacies Maps

Lithofacies maps show, by one means or another, changes in lithologic character and how it varies horizontally within the formation. This type of map has contours representing the variations in the proportion of sandstone, shale, and other kinds of rocks in the formation.

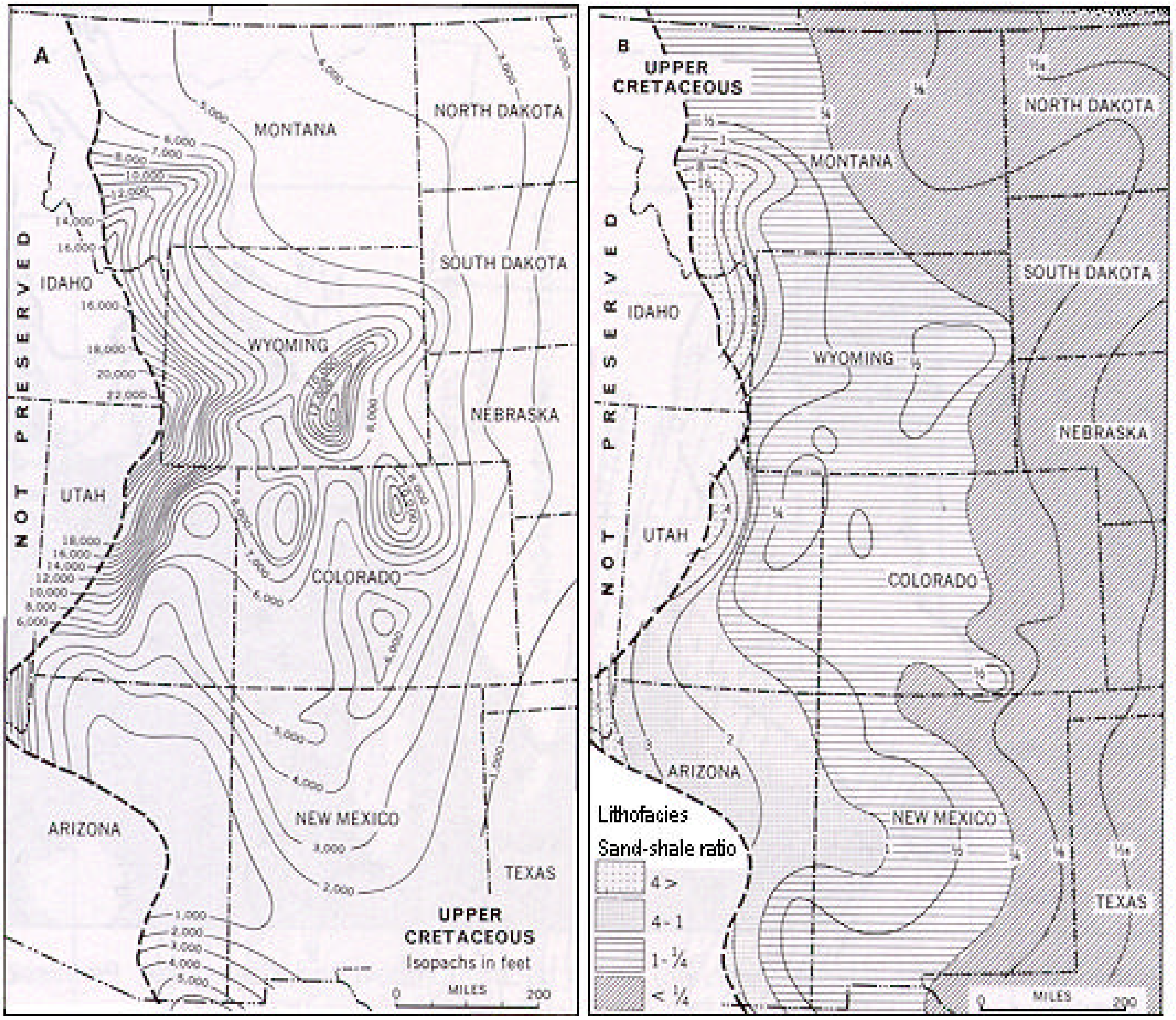


Figure 46 Isopach and lithofacies maps

Identification of source and reservoir rocks, their distribution, and their thickness' are essential in an exploration program, therefore, exploration, particularly over large areas, requires correlation of geologic sections. Correlations produce cross-sections that give visual information about structure, stratigraphy, porosity, lithology and thickness of important formations. This is one of the fundamental uses of well logs for geologists.

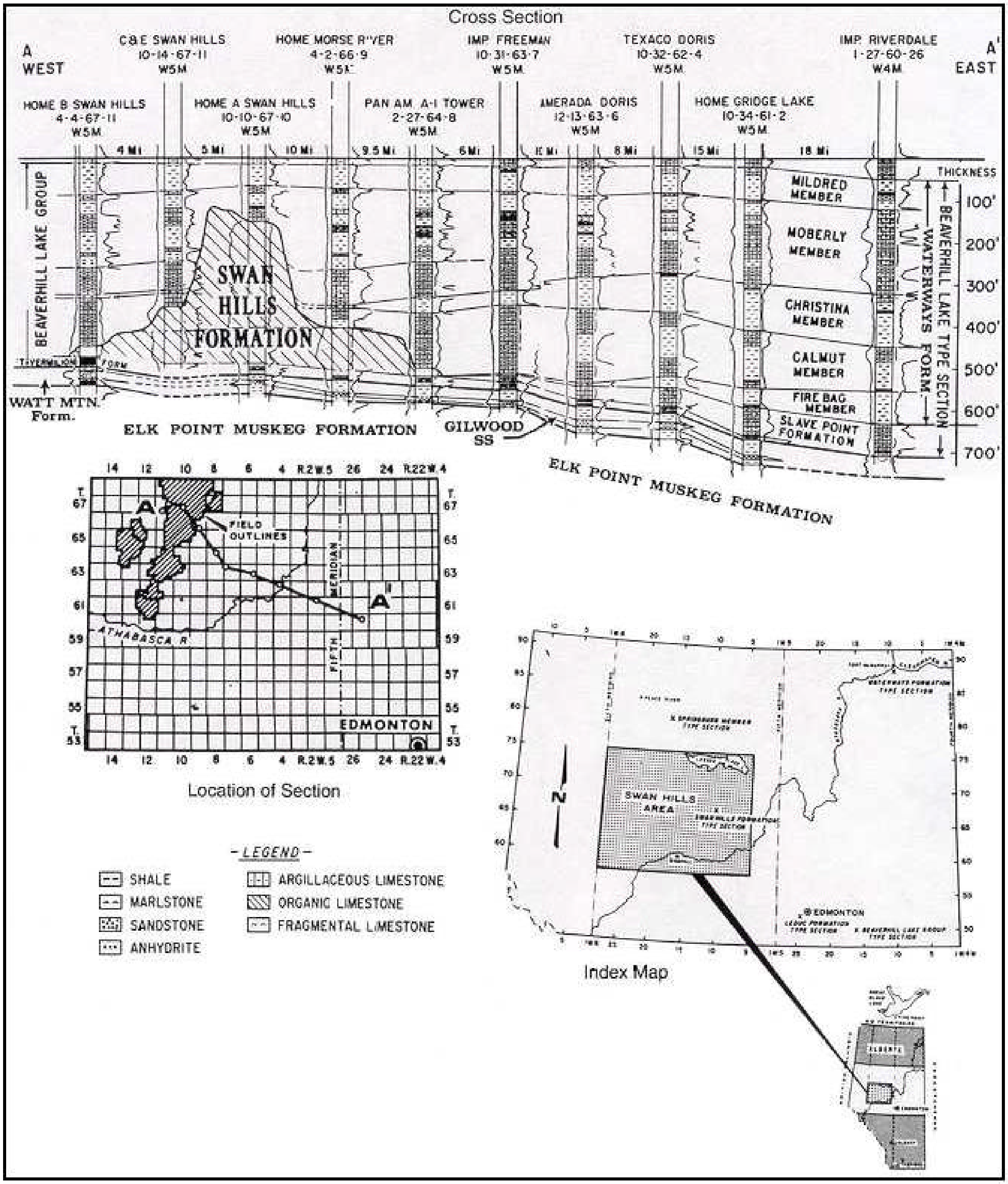


Figure 47 Cross-section constructed from correlated well logs

Wells that have information collected by driller's logs, sample logs, and wireline logs enable the geologists to predict more precisely where similar rock formations will occur in other subsurface locations.

Subsurface correlation is based primarily on stratigraphic continuity, or the premise that formations maintain the same thickness from one well to another. A major change in thickness, rock type, or faunal content can be a geologic indicator that conditions forming the strata changed, or it may be a signal of an event that could have caused hydrocarbons to accumulate.

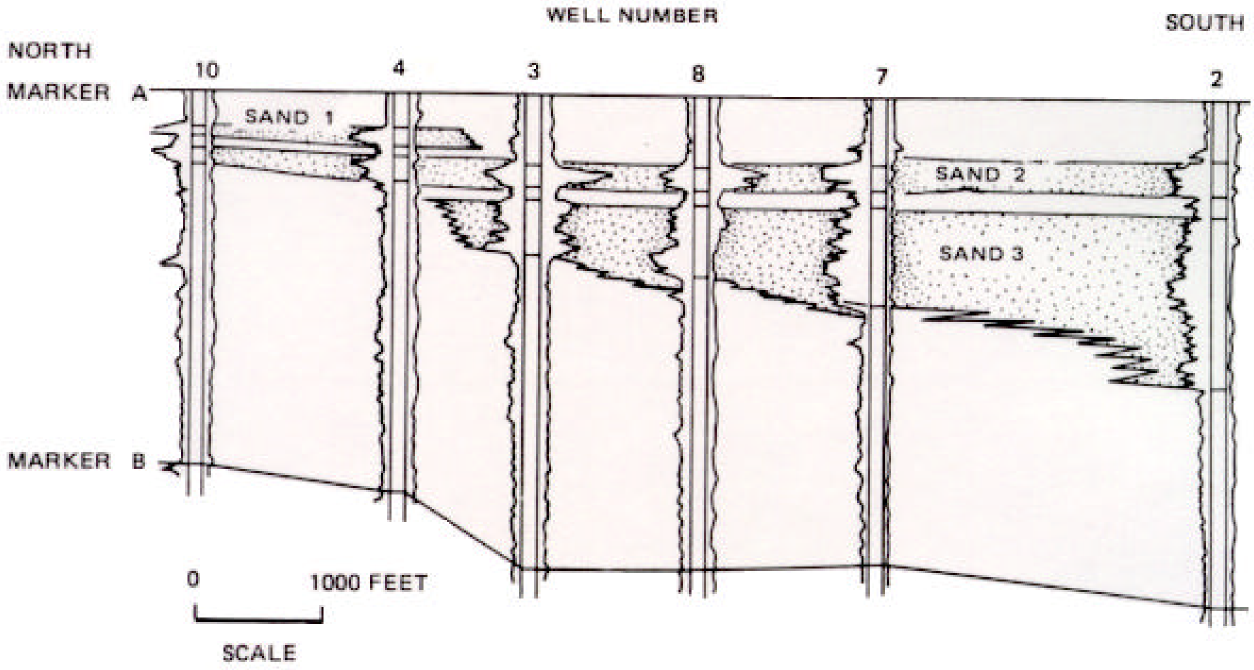


Figure 48 Stratigraphic cross-section constructed from correlated well logs showing the effect of pinchout of sand 3

Surface Geology

There are several areas to look for oil. The first is the obvious, on the surface of the ground. Oil and gas seeps are where the petroleum has migrated from its' source through either porous beds, faults or springs and appears at the surface. Locating seeps at the surface was the primary method of exploration in the late 1800's and before.

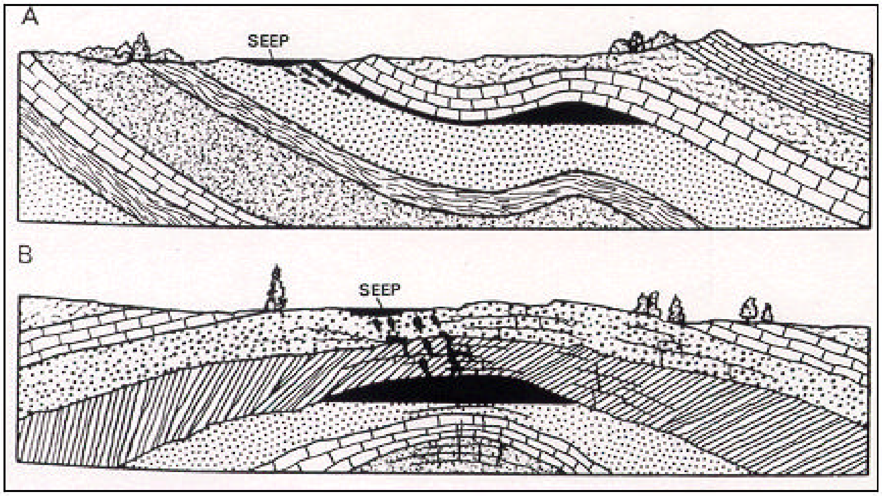


Figure 49 Seeps are located either updip (A) or along fractures (B)

Seeps are abundant and well documented worldwide. Oil or gas on the surface, however, does not give an indication of what lies in the subsurface. It is the combination of data that gives the indication of what lies below the surface. Geologic mapping, geophysics, geochemistry and aerial photography are all crucial aspects in the exploration for oil and gas.

Subsurface Geology and Formation Evaluation

Subsurface geology and formation evaluation covers a large range of measurement and analytic techniques. To complete the task of defining a reservoir's limits, storage capacity, hydrocarbon content, produceability, and economic value, all measurements must be taken into account and analyzed.

First, a potential reservoir must be discovered before it can be evaluated. The initial discovery of a reservoir lies squarely in the hands of the explorationist using seismic records, gravity, and magnetics.

There are a number of parameters that are needed by the exploration and evaluation team to determine the economic value and production possibilities of a formation. These parameters are provided from a number of different sources including, seismic records, coring, mud logging, and **wireline logging**.

Log measurements, when properly calibrated, can give the majority of the parameters required. Specifically, logs can provide a direct measurement or give a good indication of:

Porosity, both primary and secondary

Permeability

Water saturation and hydrocarbon movability

Hydrocarbon type (oil, gas, or condensate)

Lithology

Formation dip and structure

Sedimentary environment

Travel times of elastic waves in a formation

These parameters can provide good estimates of the reservoir size and the hydrocarbons in place.

Logging techniques in cased holes can provide much of the data needed to monitor primary production and also to gauge the applicability of waterflooding and monitor its progress when installed. In producing wells, logging can provide measurements of :

Flow rates

Fluid type

Pressure

Residual oil saturations

Logging can answer many questions on topics ranging from basic geology to economics; however, logging by itself cannot answer all the formation evaluation problems. Coring, core analysis, and formation testing are all integral parts of any formation evaluation effort.

Well Cuttings

Well samples are produced from drilling operations, by the drill bit penetrating the formation encountered in the subsurface. Samples are taken at regular intervals. They are used to establish a lithologic record of the well and are plotted on a strip sample log.

Cores

Cores are cut where specific lithologic and rock parameter data are required. They are cut by a hollow core barrel, which goes down around the rock core as drilling proceeds. When the core barrel is full and the length of the core occupies the entire interior of the core barrel, it is brought to the surface, and the core is removed and laid out in stratigraphic sequence. It is important to note that the sample may undergo physical changes on its journey from the bottom of the well, where it is cut, to the surface, where it is analyzed. Cores are preferable to well cuttings because they produce coherent rock. They are significantly more expensive to obtain, however. ***Sidewall cores*** are small samples of rock obtained by shooting small metal cylinders from a gun into the walls of a drill hole. Sidewall cores can be taken from several levels and at different locations by using the versatile sidewall coring gun tool. Sidewall cores may also be taken using a wireline tool called the RSCT (**Rotary Sidewall Coring Tool).**

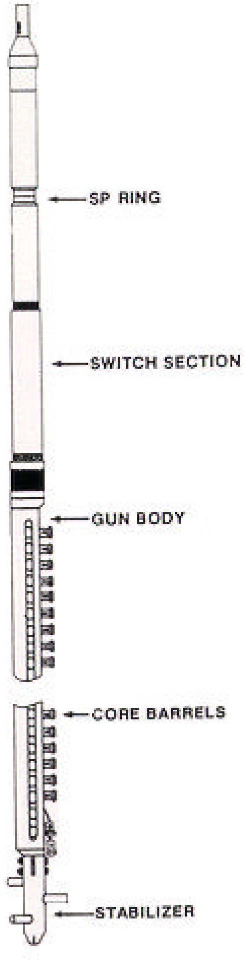


Figure 50 Conventional Sidewall Core Gun

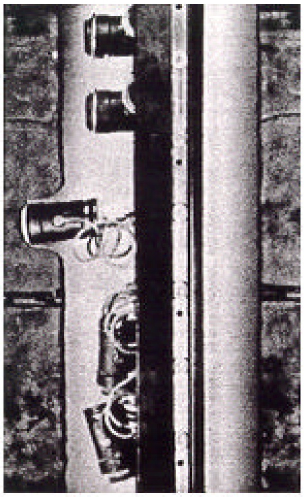


Figure 51 Wellbore view of coring gun

Logging While Drilling

Formation properties can be measured at the time the formation is drilled by use of special drill collars that house measuring devices. These logging-while-drilling (LWD) tools are particularly valuable in deviated, offshore, or horizontally drilled wells. Although not as complete as open-hole logs, the measurements obtained by MWD are rapidly becoming just as accurate and usable in log analysis procedures.

Formation Testing

Formation testing, commonly referred to as drillstem testing (DST), is a technique for delivering, to the surface, samples of fluids and recorded gas, oil, and water pressures from subsurface formations; such data allows satisfactory completion of a well. This type of testing provides more direct evidence of formation fluids and gases, the capacity of the reservoir and its ability to produce in the long term, than any other method except established production from a completed well.

Wireline formation testers complement drillstem tests by their ability to sample many different horizons in the well and produce not only fluid samples but also detailed formation pressure data that are almost impossible to obtain from a DST alone.

Wireline Well-Logging Techniques

Wireline logging involves the measurement of various properties of a formation including electrical resistivity, bulk density, natural and induced radioactivity, hydrogen content and elastic modulae. These measurements may then be used to evaluate not only the physical and chemical properties of the formation itself, but also the properties of the fluids that the formation contains. There are **open hole logs** and **cased hole logs**. The open hole logs are recorded in the uncased portion of the wellbore. Cased hole logs are recorded in the completed or cased well. There are measurements that can be made in both the open and cased holes and some that can only be made in open holes. Resistivity and density porosity are two examples of measurements that can be made in an open hole but not in a cased hole.

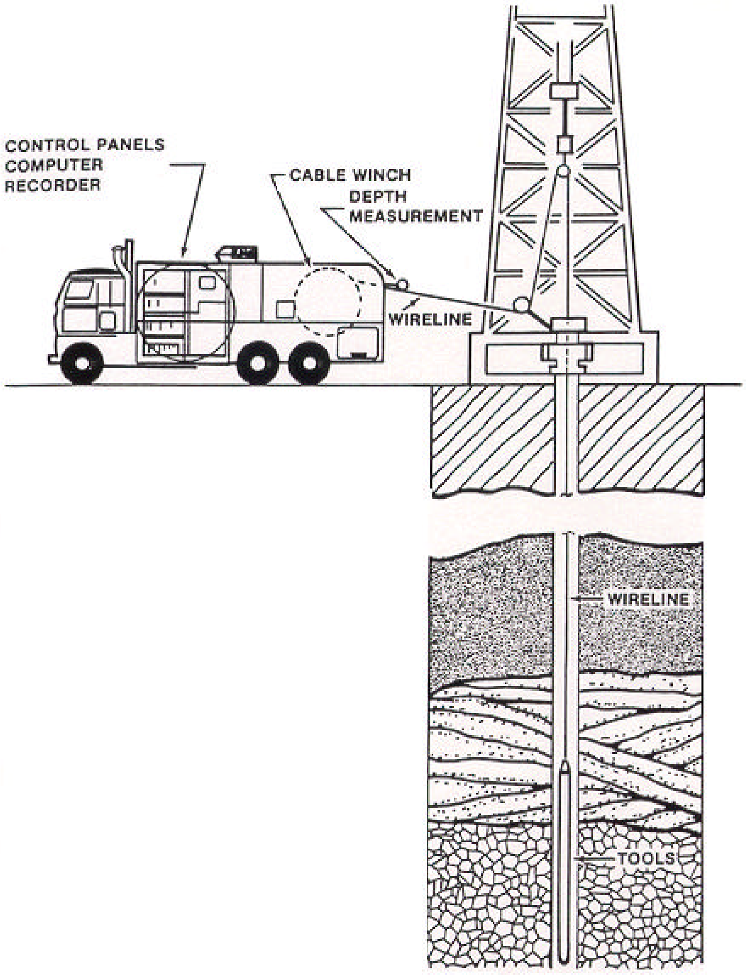


Figure 52

Perforation is the wireline procedure of introducing holes through the casing (inner wall) and/or the cement sheath into a formation so that the fluids can flow from the formation into the casing. Perforating is generally performed to bring a well into production, although it could also be performed to establish circulation within the wellbore to free a stuck tool string.

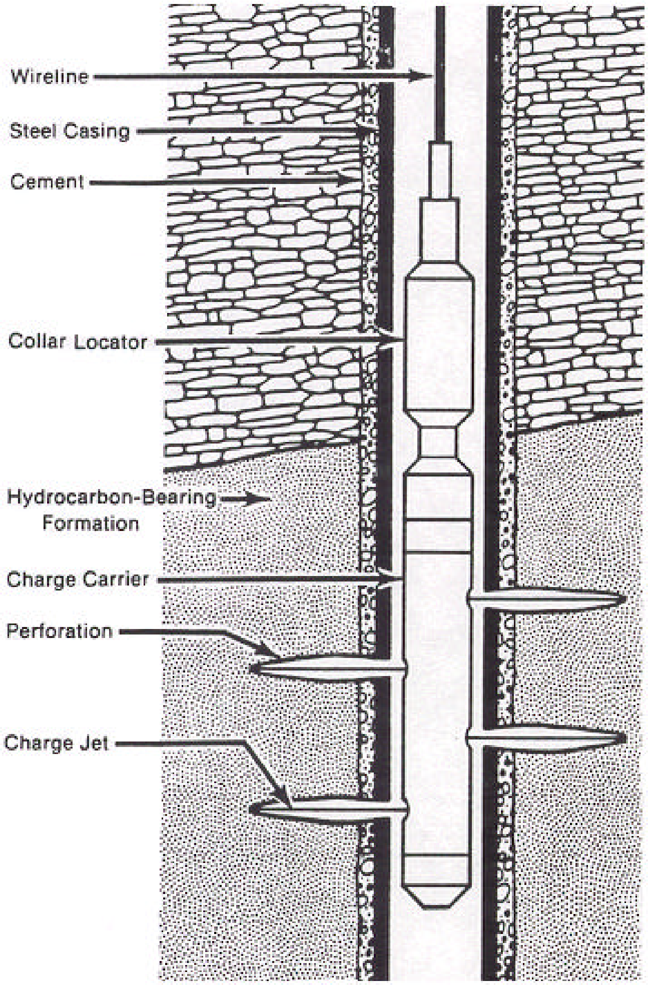


Figure 53 Perforation

Borehole Environment

Reservoir properties are measured by lowering a tool attached to a wireline or cable into a borehole. The borehole may be filled with water-based drilling mud, oil-based mud, or air. During the drilling process, the drilling mud invades the rock surrounding the borehole, which affects logging measurements and the movement of fluids into and out of the formation. All of these factors must be taken into account while logging and during log analysis. It is important to understand the wellbore environment and the following characteristics: hole diameter, drilling mud, mudcake, mud filtrate, flushed zone, invaded zone and the univaded zone.

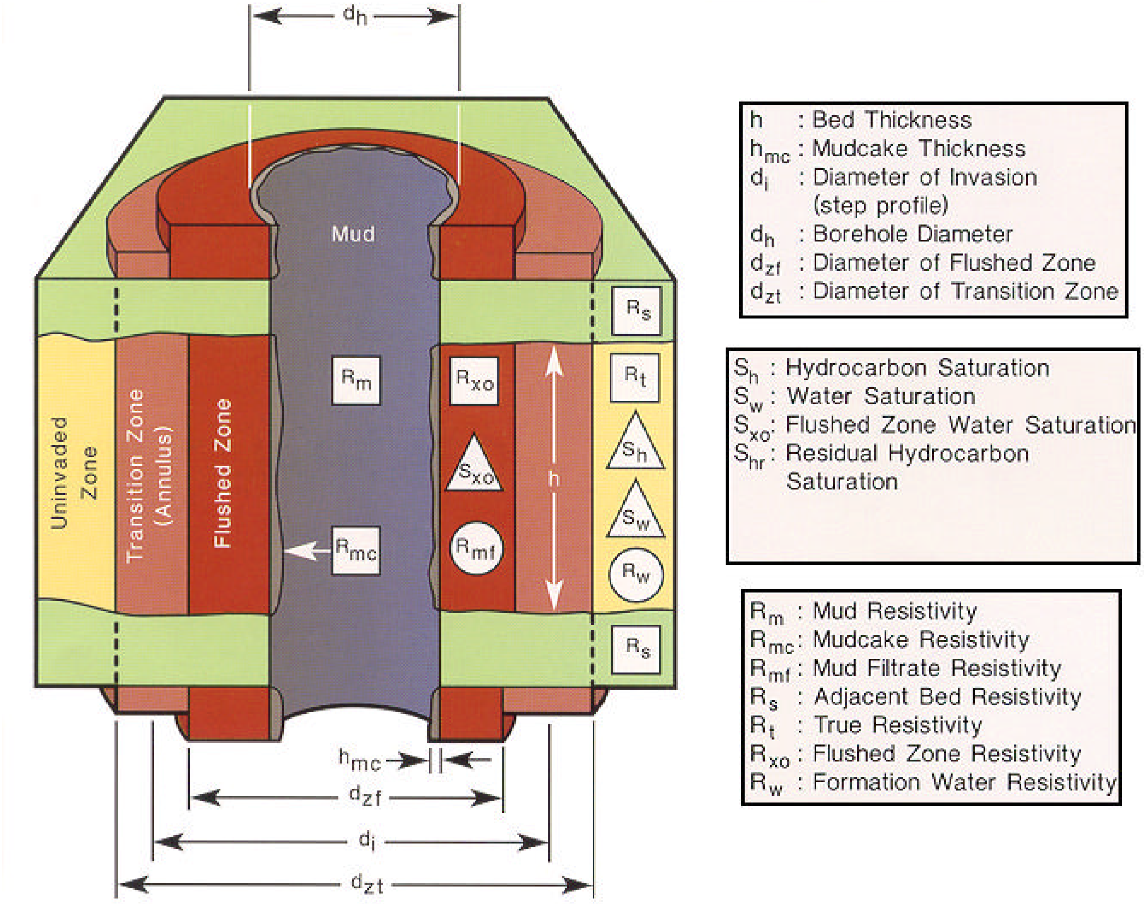


Figure 54 Borehole environment

- **Hole diameter (d_h)—** The size of the borehole determined by the diameter of the drill bit.

- **Drilling Mud Resistivity (R_m)—** Resistivity of the fluid used to drill a borehole and which lubricates the bit, removes cuttings, maintains the walls of the borehole and maintains borehole over formation pressure. Drilling mud consists of a variety of clay and other materials in a fresh or saline aqueous solution and has a measurable resistivity.

- **Mudcake Resistivity (R_{mc})—** Resistivity of the mineral residue formed by accumulation of solid drilling mud components on the wellbore walls as the mud fluids invade the formations penetrated by the borehole.

- **Mud Filtrate (R_{mf})—** Resistivity of the liquid drilling mud components that infiltrate the formation, leaving the mudcake on the walls of the borehole.

Resistivity values for the drilling mud, mudcake, and mud filtrate are determined during a full mud press and are recorded on a log's header.

- **Invaded Zone—** The zone which is invaded by mud filtrate. It consists of a flushed zone (R_{xo}) and a transition or annulus zone (R_i). The flushed zone (R_{xo}) occurs close to the borehole where the mud filtrate has almost completely flushed out the formation's hydrocarbons and/or water. The transition or annulus zone (R_i), where a formation's fluids and mud filtrate are mixed, occurs between the flushed zone (R_{xo}) and the univaded zone (R_t).

- **Uninvaded Zone (R_t)—** Pores in the univaded zone are uncontaminated by mud filtrate; instead, they are saturated with formation fluids (water, oil and/or gas).

The Basis of Log Analysis

Log analysis, at the well-site, is performed with the goal in mind of whether or not to run production casing. This decision is usually based on interpretation and calculation of the productive capacity of the formation in question. Such an analysis requires an understanding of what a log measures, the conditions that influence these measurements, and how the log data can be used to attain the goal.

Well-site analysis generally concerns the evaluation of two types of logs: electrical or resistivity logs, and porosity logs. **Resistivity and porosity are the singlemost important measurements made by conventional logging tools, and form the foundation on which the entire industry is built.** With the data presented on these logs and others, analysts can determine not only the lithology and productive capabilities of the formation of interest, but also the relative proportion of water (water saturation), and therefore hydrocarbons that the formation contains.

Log Data

The primary information we are trying to determine from log data is

1). **porosity (ϕ)**— the percentage of void space in a reservoir, of which is filled with fluid (either water or hydrocarbons).

2). **resistivity (R)**— the resistance of a material to the flow of electrical current calculated by Ohm's Law.

porosity and resistivity are used to calculate water saturation

3). **water saturation (S_w)**— the percentage of porosity of a reservoir that is filled by water.

But, we don't actually measure these parameters directly!

Porosity

To calculate porosity (ϕ) we **measure** bulk density (ρ_b), hydrogen index (HI) and/or interval transit time (Δt). A sonic tool measures internal transit time (Δt) and is used to determine the **effective porosity** of a reservoir. The neutron-density combination is used to calculate porosity two different ways, and provides us with a value of **total porosity.**

Remember

- Effective porosity is the interconnected pore volume available to free fluids. Total porosity is all void space in a rock and matrix, whether effective or noneffective.

Resistivity

Resistivity is, perhaps, the most fundamental of all measurements in logging. All geological materials posses some amount of *resistance*, or the inherent ability to resist the flow of an electrical current.

Resistivity (R) is the physical measurement of resistance, and is defined as the reciprocal of electrical conductivity (C).

$$R = \frac{1000}{C}$$

Oil and gas are electrical insulators. They will not conduct the flow of an electrical current, and therefore their resistivities are said to be infinite. Water, however, will conduct electricity depending upon its salinity. Salt water, with high concentrations of dissolved solids (e.g., NaCl, etc), will conduct electricity much more readily than will fresh water. Therefore, salt water has a much lower resistivity than does fresh water. In most instances, the water present in a formation will be saline, and will have a resistivity much lower than or similar to the resistivity of the fluid used to drill a well penetrating that formation.

A current and a voltage are **measured** using an induction or resistivity tool. From these measurements, resistivity (R) can be calculated by Ohm's Law.

$$R = \frac{V}{I}$$

The amount of current flow that can be supported by a formation depends upon the resistance of the formation matrix (i.e., rock) and the conductive properties of the fluids that formation contains. Salt water, for instance, requires very little voltage to produce a current flow. The resulting ratio of voltage to current (expressed as resistivity) is therefore low. Oil, on the other hand, requires that extremely high voltages be applied in order to generate an electrical current. It is because of this condition that the resistivity of hydrocarbons is said to be infinite (hydrocarbons are insulators).

Example of changes in resistivity with changes in reservoir characteristics

- Start with a dense quartz sandstone with no porosity. Rock is an electrical insulator→ **R = ∞.**
- Add porosity, but no fluid occupies the pores. Rock and air are electrical insulators → **R = ∞.**
- Add moderately saline water to formations porosity, typical of reservoir rocks. Current conducted through pore water → **R decreases**.
- Add even more saline water. Even more current conducted → **further decrease in R.**
- Add hydrocarbon to water already occupying porosity, hydrocarbon displaces water – occupies a volume formerly filled by water. Path of current flow becomes more tortuous → **R increases**.

Therefore, R depends on the type and amount of fluid present (which is determined by porosity). Once R has been measured, then you can solve for what proportion of that fluid is conductive formation water, and what proportion is non-conductive pore water.

Note: Formation water, at depth, is almost always saline.

Water Saturation

Water saturation (S_w) is **calculated** from porosity (ϕ) and resistivity (R) and some basic assumptions.

Assumptions

- if porosity (ϕ) is measured 2-3 inches from the borehole wall, then you must assume that to be representative of the entire formation
- deep resistivity is measured 5-7 feet from the borehole wall, then you must assume that to be representative of the univaded zone

These assumptions are used in calculating the **water saturation (S_w) of the uninvaded zone.**

Important Terminology and Symbols

R_w — Formation water resistivity

R_o — Resistivity of the formation if its porosity is filled 100% with water (wet resistivity)

F_r — Formation resistivity factor

ϕ — Porosity

a — Tortuosity factor

m — Cementation exponent

R_t — True resistivity, of the univaded zone

S_w — Water saturation

Consider a formation with a given amount of porosity, and assume that the porosity is completely filled with saline formation water of a given resistivity. Because saline water is capable of conducting an electric current, the formation water resistivity (R_w) is quite low. The measured resistivity of the formation itself (R_o, wet resistivity, where porosity is 100% filled with water) will depend upon

R_w — formation water resistivity

and F_r — formation resistivity factor $R_o = F_r \times R_w$

Rearranging this equation, the formation resistivity factor (F_r) can be quantified as the resistivity ratio of the entire formation to that of the water present in that formation.

$$F_r = \frac{R_o}{R_w}$$

In this example, formation water resistivity (R_w) is defined as a constant, therefore changes in formation resistivity factor (F_r) will occur only with changes in the overall formation resistivity (R_o). The one way in which R_o can change in a formation of constant R_w is by changing the amount of fluid available to conduct an electrical current. This is accomplished through changes in porosity. As porosity decreases, the amount of water available to conduct electrical current is decreased, resulting in an increase in formation resistivity (R_o). Therefore, formation resistivity factor (F_r) is inversely proportional to porosity (ϕ).

$$F = \frac{1}{\Phi}$$

This relationship between formation resistivity and porosity was first researched by G. E. Archie, of the Humble Oil Company, while working on limestones in France. Archie had electric (resistivity) logs from several wells, and core porosity from productive zones within these wells. He noticed that there was some relation between resistivity and porosity, and thus was able to identify zones of interest through the use of electric logs alone. What he wanted to know was if there was some relationship that made it possible to determine whether a zone would be productive on the basis of measured resistivity and core porosity.

Changes in the porosity of a formation may have effects other than simply increasing or decreasing the amounts of fluids available to conduct electric current. With a change in porosity, there may be concomitant changes in the complexity of the pore network that affect the conductive nature of the fluids present, and formation resistivity factor (F_r) can therefore vary with the type of reservoir. These changes are expressed by

(a) — tortuosity factor

and (m) — cementation exponent

$$F_r = \frac{a}{\Phi^m}$$

For the limestones of Archie's experiments, the tortuosity factors and cementation exponents were always constant ($a = 1.0$, $m = 2.0$). However, this may not be the case for sandstone reservoirs. Although both parameters can be determined experimentally for a specific reservoir, log analysts commonly use set values for tortuosity factor (a) and cementation exponent (m), depending upon lithology and porosity, which are presented below.

Table 2 Standard values for tortuosity factor (a) and cementation exponent (m).

	Carbonates	Sandstones	
		Porosity Φ > 16% (Humble)	Porosity Φ < 16% (Tixier)
Tortuosity (a)	1.0	0.62	0.81
Cementation (m)	2.0	2.15	2.00

Consider now that the porous formation discussed previously is filled with some combination of conductive formation water of constant resistivity (R_w) , and oil. Oil is an insulator and will not conduct an electrical current. Furthermore, because the formation is filled with both water and oil, the resistivity of the formation can no longer be referred to as wet resistivity (R_o). The measure of formation resistivity in this instance—taking into account the resistivity of the rock matrix and the fluids contained—is called **true resistivity (R_t).** True resistivity of a formation will only be equal to wet resistivity ($R_t = R_o$) when that formation is completely filled with conductive water. However, because some of the available porosity may be filled with non-conductive oil, the theoretical wet resistivity (R_o) of that formation is now related to the measured true resistivity (R_t) by some additional factor, referred to as F'.

$$R_o = F' \times R_t$$

The factor F' can therefore be expressed as a ratio of the theoretical wet resistivity of that formation (R_o) to the actual measured resistivity of the formation (R_t).

$$F' = \frac{R_o}{R_t}$$

In the example formation, because both porosity and formation water resistivity are considered to be constant, the resulting theoretical wet resistivity (R_o) will be constant. Therefore, changes in the factor F' will occur with changes in measured resistivity (R_t). Under the given conditions, the only way in which true measured resistivity (R_t) of the formation can change is through the addition or subtraction of conductive fluid.

For example, the addition of oil to the reservoir would result in the increase of that formation's measured resistivity (R_t) because some amount of conductive formation water would be displaced by the oil. Therefore, the factor F' is dependent upon the relative proportion of conductive fluids (water) and non-conductive fluids (hydrocarbons) in the formation.

The **factor** F' in the above equations represents **water saturation** (usually expressed S_w) which is the percentage of pore space within a formation that is occupied by conductive formation water. By substitution of equations, water saturation can be related to the physical properties of the formation and the conductive properties of the fluids it contains.

$$S_w{}^n = \frac{F \times R_w}{R_t} \qquad \text{or} \qquad S_w{}^n = \frac{a}{\Phi^m} \times \frac{R_w}{R_t}$$

Water saturation is related to these properties by the exponent n (saturation exponent). The saturation exponent may have a range of values dependent upon specific reservoir conditions, but generally is assumed to be equal to 2.0. With knowledge of the production characteristics of the formation in question, it is possible to determine more accurate values for the saturation exponent.

The equation for water saturation, an expanded version of that presented as a footnote in Archie's 1942 publication, and commonly referred to as "**Archie's equation**," has become the foundation of the entire industry of well logging. In its simplest form, Archie's equation is often expressed as:

$$S_w = \sqrt[n]{\frac{a}{\Phi^m} \times \frac{R_w}{R_t}}$$

where: n = saturation exponent

(commonly $n = 2.0$)

a = tortuosity factor

ϕ = porosity

m = cementation exponent

R_w = formation water resistivity

R_t = true formation resistivity

A note on water saturation

It is important to realize that while water saturation (S_w) represents the percentage of water present in the pores of a formation, it does not represent the ratio of water to hydrocarbons that will be *produced* from a reservoir. Shaly sandstone reservoirs with clay minerals that trap a large amount of formation water may have high water saturations, yet produce only hydrocarbons. Saturations simply reflect the relative proportions of these fluids contained in the reservoir. Nonetheless, **obtaining accurate values for water saturation is the primary goal of open-hole log analysis**. With the knowledge of water saturation, it is possible to determine that percentage of porosity that is filled with a fluid other than water (i.e., hydrocarbons), and therefore hydrocarbon reserves.

Review of Permeability

As previously stated, permeability is the property that permits the passage of a fluid through the interconnected pores of a rock.

Permeability is measured in darcies. A rock that has a permeability of 1 darcy permits 1 cc of fluid with a viscosity of 1 centipoise (viscosity of water at 68°F) to flow through one square centimeter of its surface for a distance of 1 centimeter in 1 second with a pressure drop of 14.7 pounds per square inch.

Few rocks have a permeability of 1 darcy, therefore permeability is usually expressed in millidarcies or 1/1000 of a darcy.

The permeabilities of average reservoir rocks generally range between 5 and 1000 millidarcys. A reservoir rock whose permeability is 5 md or less is called a tight sand or a dense limestone, according to composition. A rough field appraisal of reservoir permeabilities is:

Fair	1-10 md
Good	10-100 md
Very good	100-1,000 md

- **Absolute Permeability (K_a)**— Permeability calculated with only one fluid present in the pores of a formation.
- **Effective Permeability (K_e)—** The ability of a rock to conduct one fluid in the presence of another, considering that both fluids are immiscible (e.g., oil and water). Effective permeability depends not only on the permeability of the rock itself, but also on the relative amounts of the different types of fluid present.
- **Relative Permeability (K_r)—** The ratio of a fluid’s effective permeability to the formation’s absolute permeability (100% saturated with that fluid). Relative permeability reflects the amount of a specific fluid that will flow at a given saturation — in the presence of other fluids — to the amount that would flow at a saturation of 100%, with all other factors remaining the same.

The following chart illustrates the relative permeabilities of oil and water in an **example formation**. In a reservoir 100% saturated with oil, the relative permeability of oil (K_{ro}) to water is equal to 1. As water saturation increases, the relative permeability of oil to water will begin to decrease. The value of water saturation where no water will flow is referred to as **irreducible water saturation (S_{wirr})**. At some value of water saturation, water will begin to flow within the formation because it can no longer be contained by capillary pressure. With increasing water saturation, the relative permeability of oil (K_{ro}) to water will continue to decrease. Meanwhile, the relative permeability of water (K_{rw}) to oil will increase. Eventually, a value of water saturation will be reached at which the relative permeability of oil (K_{ro}) to water is 0. At this point, oil will no longer flow within the reservoir, and that value of water saturation is referred to as **residual oil saturation (ROS).** At water saturations above the residual oil saturation, only water will flow within the reservoir. In a reservoir 100% saturated with water, the relative permeability of water (K_{rw}) to oil is equal to 1.

Notice from Chart 3 that there is a point at which the relative permeability of oil (K_{ro}) is equal to the relative permeability of water (K_{rw}). At this value of water saturation (approximately 55% in this example), both oil and water will flow with equal ease. This does not mean that the same amounts of oil and water will be produced from the reservoir. The amount of fluid flowing is not a direct effect of the relative permeability of a fluid because different fluids have different viscosities. For example, if water and gas were existing in a reservoir and had equal relative permeabilities ($K_{rw} = K_{rg}$), the more gas would flow within the formation because the viscosity of gas is much lower than that of water.

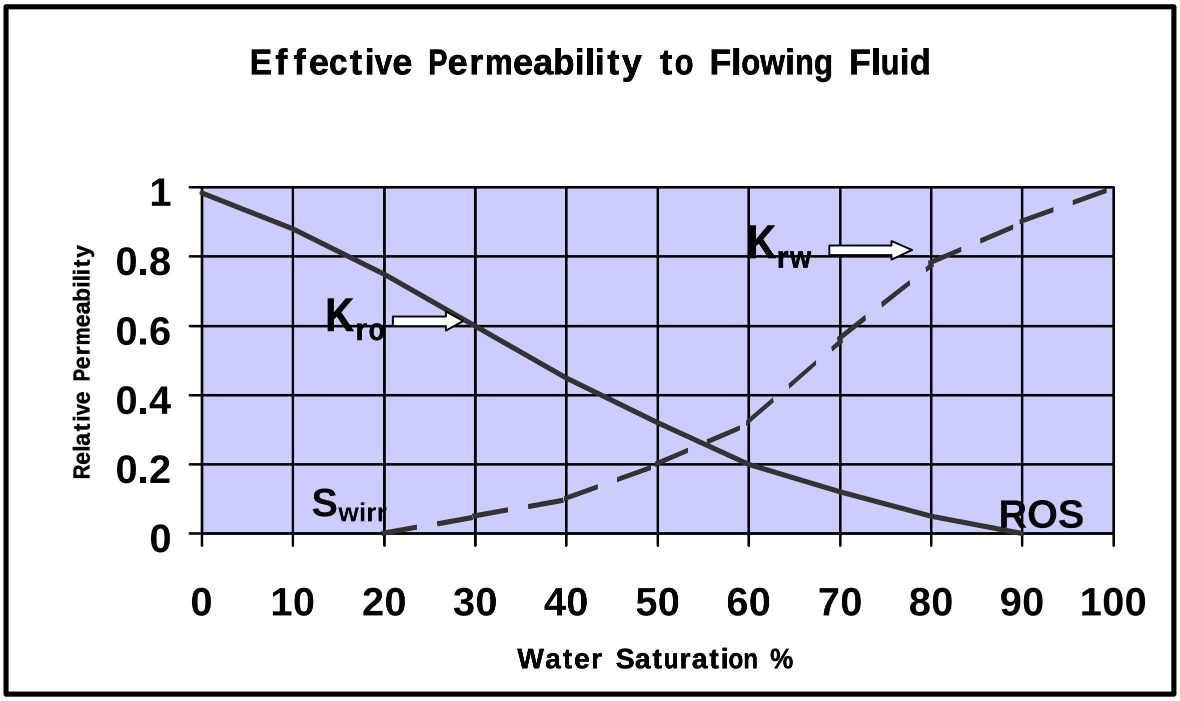


Chart 3

Reserve Estimation

Accurately estimating the reserves of hydrocarbons in the reservoir is extremely important. This calculation not only relies on computations from log data but also on the size and shape of a reservoir, and correlations of logs from many wells in the field. Dipmeter data and seismic data also assist the analyst in making accurate calculations. In summary, a log analyst can say with some reasonable degree of certainty that, for example, 10% of the volume of the reservoir is full of oil. It is up to others to determine the size of the reservoir and therefore deduce the actual volume of oil available.

How much hydrocarbon can be recovered from the reservoir?

First, calculations need to be made to determine the volume of hydrocarbon found in a trap or the OIP (oil-in-place). This is accomplished when some reservoir thickness (h) is delineated to exist over an area (A) to produce a volume (V). If (h) is measured in feet and (A) in acres, the reservoir volume (V) is expressed in acre-feet.

In actual reservoirs, both porosity and saturation vary laterally and vertically. A useful quantity for oil-in-place measurements is therefore the hydrocarbon pore volume, or HCPV, which is defined as:

$$HCPV = \Phi(1-Sw)$$

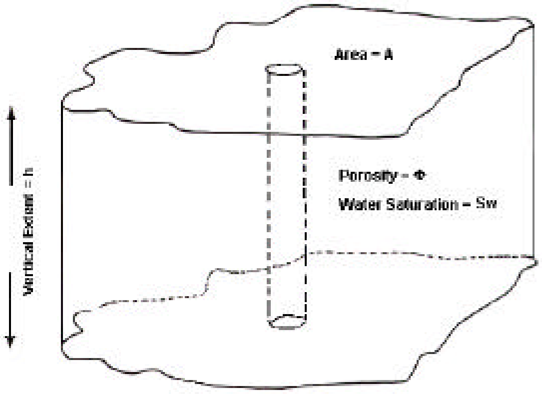


Figure 55 Oil-in-place

Thus, at any depth in a well, if both porosity and saturation are deduced from logs the concentration of hydrocarbon in the reservoir at that depth can be estimated. For example, if porosity is 30% and water saturation is 40%, then HCPV = 0.3(1-0.4) = 0.18 or 18% of the bulk-reservoir volume contains oil. At a neighboring point in the same well, the value of HCPV may be different. Thus, in order to sum the total oil-in-place (OIP), an integration of HCPV with respect to depth and area is called for:

$$OIP = \Sigma\, \Phi(1-Sw)h * A$$

Second, we must convert the oil-in-place to reserves which requires two additional pieces of data: the recovery factor (r) and the formation volume factor (B). Neither of these can be estimated from logs. The recovery factor is a function of the type of reservoir and the drive mechanism, and the formation volume factor is a function of the hydrocarbon properties. The reserves (N), in terms of stock tank volumes, are thus expressed as

$$N = \frac{C * \Sigma \Phi (1 - Sw) h * A * r}{B}$$

Reserves (N) are expressed in stock tank barrels at Standard Temperature and Pressure (STP).

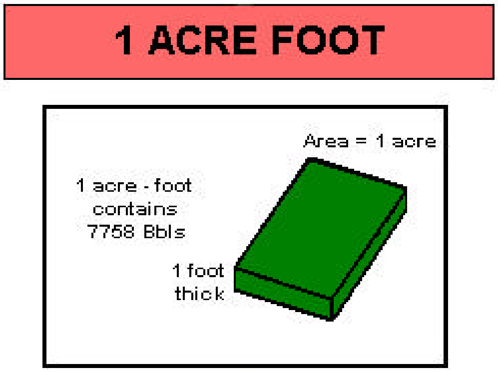


Figure 56

where: C = a constant, 7758 bbl/acre

A= acres

Φ = porosity of reservoir, in percent

h = thickness of reservoir, in feet

Sh = hydrocarbon saturation, in percent

= 1-Sw (water saturation)

r = recovery factor

B = formation volume factor or shrinkage factor

$$= 1.33 \pm 0.16$$

$$= \frac{\text{volume at downhole conditions}}{\text{volume at STP}}$$

Appendix

Chemical Properties of Hydrocarbons

As previously stated, hydrocarbons are formed from the alteration of sediment and organic materials. They are the simplest organic compounds, consisting of only carbon and hydrogen. They are classified according to the ratio of carbon and hydrogen, their molecular structure, and their molecular weight. Hydrocarbons have been divided into various series, differing in chemical properties and relationships. The four that comprise most of the naturally occurring petroleums are the normal paraffin (or alkane) series, the isoparaffin (or branched-chain paraffin) series, the naphthene (or cycloparaffin) series, and the aromatic (or benzene) series. A fifth group is the NSO compounds, which are hydrocarbon compounds that sometimes contain substantial amounts of nitrogen, sulphur, oxygen, and other minor elements.

1). The Paraffin Series — these are compounds in which each carbon atom is completely saturated with respect to hydrogen. Structures include simple straight chains (alkanes) of carbon atoms and branched chains (isoparaffin or isoalkanes). The paraffin hydrocarbons, sometimes called the methane series, are chemically inactive. Methane is the simplest of all the hydrocarbons and is also the most stable. Members of the paraffin series are generally the most abundant hydrocarbons present in both gaseous and liquid petroleums.

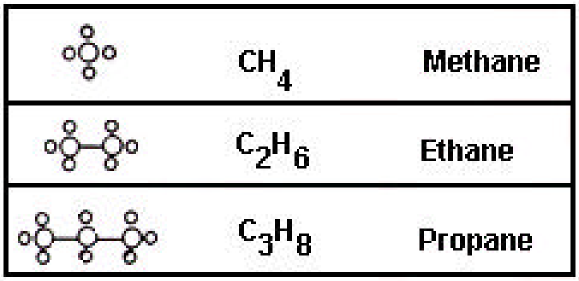


Figure 57 Straight chain paraffin molecular structure

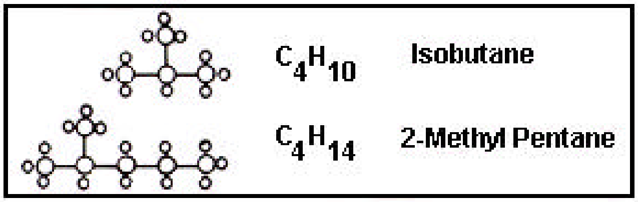


Figure 58 Branched chain paraffin molecular structure

2). The Naphthene (Cycloparaffin) Series — these are saturated compounds which have a cyclic arrangement (closed-ring) of the carbon atoms with only single valences connecting the carbon atoms.

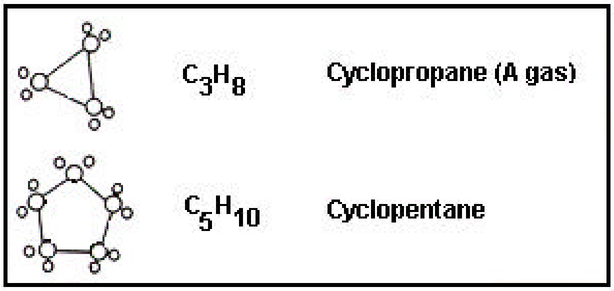


Figure 59 Cycloparaffin molecular structure

3). The Aromatic (Benzene) Series — these hydrocarbons, so named because many of its members have a strong or aromatic odor, are a group of unsaturated hydrocarbons with a cyclic structure. Benzene, a colorless, volatile liquid, is the parent and most common member of the series found in petroleums. They include several important biomarker compounds that allow oils and source rocks to be correlated. Biomarkers are compounds found in crude oils and source rock extracts that can be unmistakably traced back to living organisms

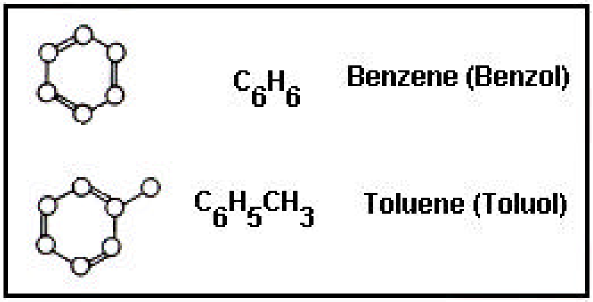


Figure 60 Aromatic molecular structure

4). NSO compounds— these are known as heterocompounds and are subdivided into the resins and asphaltenes. They form by combining the organic carbon and hydrogen with other elements, predominantly nitrogen (N), sulfur (S), and oxygen (O), in complex molecules.

Nearly all crude oils contain small quantities of nitrogen. Nothing is known of the nature of the nitrogen compounds in undistilled crude oil, but the nitrogen compounds in the distillates are frequently of the general type known as pyridines (C_5H_5N) and quinolines (C_9H_7N). Since nitrogen is a common, inert constituent of natural gas, it may be that the nitrogen content of the crude oil is contained in the dissolved gases. Nitrogen is an unwanted component of both crude oil and natural gas.

Sulfur occurs to some extent in practically all crude oils and in each of the fractions that make up the oil. It may be in one of the following forms: free sulfur, hydrogen sulfide (H_2S), or organic sulfur compounds. The presence of sulfur and sulfur compounds in gasoline causes corrosion, bad odor, and poor explosion. Before the development of modern cracking processes by refineries, the presence of sulfur made petroleum less desirable and consequently worth less per barrel. Since sulfur can now be removed from oil, this price differential has been largely eliminated, and sulfur-bearing crude oils are nearly equal to nonsulfur crudes.

Oxygen is found in crude oil and occurs in the following various forms: free oxygen, phenols (C_6H_5OH), fatty acids and their derivatives, and naphthenic acids.

Glossary

Accretion—The process by which an object grows larger due to the addition of fresh material to the outside.

Catagenesis—Middle level (between diagenesis and metagenesis) sediment consolidation and alteration when most oil and gas are generated.

Cementation—Precipitation of mineral material into intergranular or intercrystalline pore space.

Chalk—Fine-textured marine limestone formed by shallow water accumulation of calcareous remains of floating micro-organisms and algae.

Clast—A rock fragment.

Clastic (rock)—A rock composed of clasts.

Compaction—Sediment volume decrease by increase in overburden pressure.

Crystallization—Physical and/or chemical conversion of gaseous or liquid material to solid crystal.

Diagenesis—The process of converting sediment to rock.

Differentiation—The process by which planets and satellites develop concentric layers of different compositions.

Dissolution—When solid material in sediment dissolve in interstitial solutions.

Dolomite—Calcium magnesium carbonate: $(CaMg(CO_3)_2$.

Dolomitization—A volume-reducing recrystallization process which adds the magnesium ion to calcium carbonate to form dolomite: can occur contemporaneously with deposition or diagenetically.

Induration—The hardening of a rock or rock material by heat, pressure, or the introduction of cementing material.

Intergranular—Between the grains of a rock.

Intragranular—Within the grain of a rock.

Lithification—Solidification of sediment to rock: induration, diagenesis.

Metagenesis—Late stage diagenesis to early metamorphism corresponding to dry gas generation and thermally over-mature petroleum source sediments.

Oxidation—The chemical combination of oxygen with other substances resulting in compositional change and elimination of organic material.

Oxidizing environment—A depositional environment in which oxidation occurs. Chemical elimination of organic material occurs in an oxidizing environment.

Precipitation—The process by which dissolved materials come out of solution.

Recrystallization—The generation of new, usually larger, crystals in a rock.

Reducing environment—A depositional or ecological condition in which oxygen is diminished or eliminated.

Replacement—A subsurface water process involving solution exchange of one mineral for another in a rock medium.

Specific gravity—The ratio of the density of a substance to the density of water.

Terrigenous—Derived from the land: terrigenous sediment.

Viscosity—The property of a substance to offer internal resistance to flow; its internal friction.

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