MINING ENGINEERING - UNIVERSITY OF JOS

PETROLEUM RESERVOIR ENGINEERING

MNE 505

Petroleum engineering is a field of engineering that deals with the activities related to the production of hydrocarbons, either crude oil or natural gas. Exploration and production are deemed to fall within the upstream sector of the oil and gas industry. Exploration by earth scientists and production by petroleum engineers are the oil and gas industry's two main subsurface disciplines, focusing on maximizing economic recovery of hydrocarbons from subsurface reservoirs. Petroleum geology and geophysics focus on provision of a static description of the hydrocarbon reservoir rock, while petroleum engineering focuses on estimation of the recoverable volume of this resource using a detailed understanding of the physical behavior of oil, water and gas within porous rock at very high pressure.

The combined efforts of **geologists** and **petroleum engineers** throughout the life of a hydrocarbon accumulation determine the way in which a reservoir is developed and depleted, and usually they have the highest impact on field economics. Petroleum engineering requires a good knowledge of many other related disciplines, such as geophysics, petroleum geology, formation evaluation (well logging), drilling, economics, reservoir simulation, reservoir engineering, well engineering, artificial lift systems, completions and petroleum production engineering.

A typical workflow for designing, implementing, and executing a project to produce hydrocarbons must fulfill several functions. The workflow must make it possible to identify project opportunities; generate and evaluate alternatives; select and design the desired alternative; implement the alternative; operate the alternative over the life of the project, including abandonment; and then evaluate the success of the project so lessons can be learned and applied to future projects. People with skills from many disciplines are involved in the workflow. For example, petroleum geologists and geophysicists use technology to provide a description of hydrocarbon-bearing reservoir rock. Petroleum engineers acquire and apply knowledge of the behavior of oil, water, and gas in porous rock to extract hydrocarbons.

Figure 1 illustrates a hydrocarbon production system as a collection of sub-systems. Oil, gas, and water are contained in the pore space of reservoir rock. The accumulation of hydrocarbons in rock is a reservoir. Reservoir fluids include the fluids originally contained in the reservoir as well as fluids that may be introduced as part of the reservoir management program. Wells are needed to extract fluids from the reservoir. Each well must be drilled and completed so that fluids can flow from the reservoir to the surface.

Well performance in the **reservoir** depends:

a. Properties of the reservoir rock,

b. Interaction between the rock and fluids,

c. Properties of the fluid flowing through the well;

d. The well length, cross section, and trajectory; and

e. Type of completion.

Surface equipment is used to drill, complete, and operate wells. Drilling rigs may be permanently installed or portable. Portable drilling rigs can be moved by vehicles that include trucks, barges, ships, or mobile platforms. Separators are used to separate produced fluids into different phases for transport to storage and processing facilities. Transportation of produced fluids occurs by such means as pipelines, tanker trucks, double-hulled tankers, and liquefied natural gas transport ships. Produced hydrocarbons must be processed into marketable products. Processing typically begins near the well site and continues at refineries. Refined hydrocarbons are used for a variety of purposes, such as natural gas for utilities, gasoline and diesel fuel for transportation, and asphalt for paving.

Petroleum engineers are expected to work in environments ranging from desert climates in the Middle East, stormy offshore environments in the North Sea, and arctic climates in Alaska and Siberia to deep-water environments in the Gulf of Mexico and off the coast of West Africa.

Petroleum engineers tend to specialize in one of three sub-disciplines:

I. **Drilling engineering**: Drilling engineers are responsible for drilling and completing wells.

II. **Production engineering**: Production engineers manage fluid flow between the reservoir and the well.

III. **Reservoir engineering**: Reservoir engineers seek to optimize hydrocarbon production using an understanding of fluid flow in the reservoir, well placement, well rates, and recovery techniques.

BASIC EARTH GEOLOGY

Since the occurrence of crude oil and natural gas are intrinsically associated with reservoir rocks, we must start our discussion of the origin and occurrence of natural hydrocarbons with petroleum geology. Geology is the study of all processes that affect the earth. The earth processes studied by geologists occur at many scales from those at the planetary scale (plate tectonics; interactions between the earth's core, mantle, and crust; etc.) to those at the grain and pore scale (formation of the cementation that binds sand grains, swelling of clays in pores, etc.). **Figure 1** shows a schematic diagram (***not to scale***) of the Earth's Structure

Through ***radiometric dating***, the earth is believed to be approximately **4.54 billion years old.** As shown in **Figure 1**, it is composed of an ***inner* and *outer core***, the ***mantle***, and the ***crust***. The earth's crust is the thin, solid, outer shell of the planet that we live on and interact with on a daily basis. The earth's crust accounts for approximately 1% of the total volume of the planet.

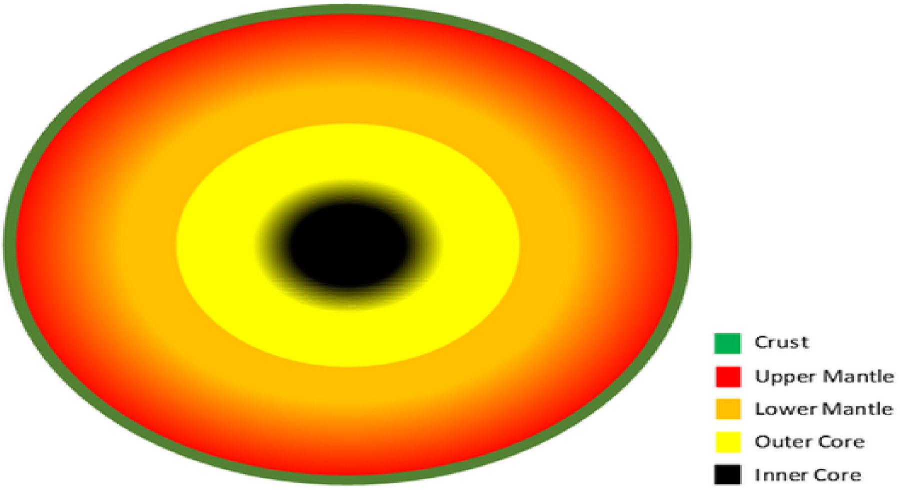


Fig. 1: Schematic Representation of Earth

The solid crust is the upper layer of the lithosphere (the lithosphere is composed of rigid crust and upper portions of the semi-elastic mantle). The earth's crust can be further divided into the oceanic crust and the continental crust. The oceanic crust is between 3 miles (5 km) and 6 miles (10 km) thick and is overlain by approximately 3 miles of seawater; while the continental crust is between 20 miles (30 km) and 30 miles (50 km) thick. Underlying the oceanic crust and the continental crust is a layer of basalt. Because both the oceanic crust and the continental crust are less dense than the mantle, they both "float" on the mantle

This floating of the crust on the mantle gives rise to the widely accepted theory of Plate Tectonics. Plate Tectonics is the theory that describes the motion of the continents over the geologic time scale. In this theory, the lithosphere is broken into several major tectonic plates and many smaller plates. The major plates are associated with one of the continents. Slow moving convection currents in the upper mantle are the primary driving mechanisms of plate tectonics; while other mechanisms related to gravity are considered to be secondary driving mechanisms. This is illustrated in **Figure 2**.

In this figure, four tectonic plates are shown along with the convection currents that are driving their drift. The direction of the tectonic drift is shown by the arrows. The separation of tectonic plates is referred to as rifting and is caused by the spreading of two or more convection currents. The mid-Atlantic Ridge is an example of ***rifting zone.*** Subduction of tectonic plates, where one plate slides below another plate, results when two or more tectonic plates traveling towards each other collide. The resulting zone is called a ***subduction zone.*** A third type of plate boundary, where one plate grinds past another plate, is called a ***transformational boundary.*** An example of a transformational boundary is the San Andreas Fault where the Pacific Tectonic Plate is moving across the North American Tectonic Plate.

Due to the friction and built-up stresses in subduction zones and transformational boundaries, these plate boundaries are often associated with volcanism and earthquakes. In fact, the ***"Ring of Fire"*** which surrounds the Pacific rim and the North American west coast is caused by the movement of tectonic plates interacting with the Pacific Tectonic Plate.

Rift zones and subduction zones are the only locations where mass transfer from the crust to the mantle (and vice versa) can occur. At a rift zone, fresh rock materials are expelled from the mantle; while at a subduction zone, weathered rock material is returned to the mantle. As we will see, this forms an integral part of the ***Rock Cycle***.

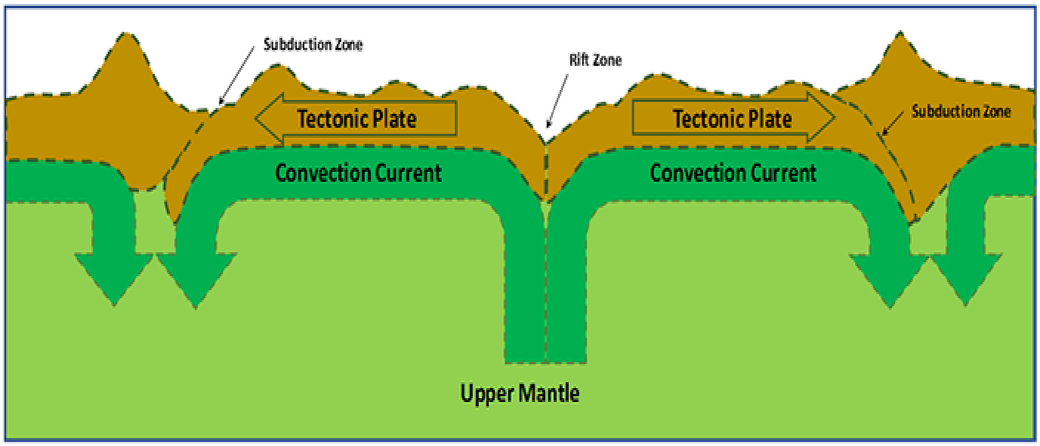


Fig. 2: Schematic Representation of Plate Tectonics

Rock Types and the Rock Cycle

There are three primary rock types present on the earth:

a. *Igneous rocks,*
b. *Sedimentary rocks* and,
c. *Metamorphic rocks*.

1. **Igneous rocks** are rocks formed by the cooling and solidification of molten rock material. As such, igneous rocks are associated with **volcanology.**

There are two types of igneous rocks: **intrusive igneous rocks and extrusive igneous rocks.** Intrusive igneous rocks crystalize below the earth's surface, allowing for slow cooling and the development of large crystal structures, while extrusive igneous rocks crystalize on the surface, resulting in rapid cooling and the development of small crystal structures. Examples of intrusive igneous rocks include **diorite, granite, and peridotite**; while examples of extrusive igneous rocks include **basalt, pumice, and tuff.**

2. **Sedimentary rocks** are rocks formed by the accumulation of sediments. There are three types of sedimentary rocks: **clastic sedimentary rocks, chemical sedimentary rocks, and organic sedimentary rocks.** Clastic sedimentary rocks are rocks formed by the accumulation of debris that has been **mechanically broken** by earth processes such as weathering and erosion. Examples of clastic sedimentary rocks include **sandstones, siltstones, and shales. Chemical sedimentary rock** are rocks that are formed by the precipitation of dissolved materials from high mineral content brines. Examples of chemical sedimentary rocks include **rock salt**, **chert,** some **limestones**, and some **dolomites**. Finally, **organic sedimentary rocks** are formed from the accumulation of organic materials (dead plants or animals). Examples of organic

sedimentary rocks include **coal,** some **limestones,** and some **dolomites**.

3. **Metamorphic rocks** are rocks that started as some other rock type (igneous or sedimentary) but have been substantially altered from their original form by **excessive heat, pressure, or exposure to high mineral content brines** (or combinations of these three mechanisms). Examples of metamorphic rocks include **marble, gneiss,** and **schist.**

Crude oil and natural gas reside in the pore-spaces between the grains that make up the ***rock fabric*** of the reservoir rock. Consequently, the overwhelming majority of hydrocarbon reservoirs occur in sedimentary rocks where the pore-spaces in the accumulated sediments are sufficiently large to allow for the storage of crude oil and natural gas. While the pore-spaces in metamorphic and igneous rocks are too small to allow for the entry of hydrocarbon molecules, if these rock formations are mechanically fractured by tectonic forces, then the space created by the natural fractures can allow for hydrocarbon storage, and fractured reservoirs in metamorphic and igneous rocks are possible.

It should be emphasized that the formation of rock is not a static process, but is more of a dynamic, cyclical process. In other words: when a rock is formed, it is continually acted upon by earth processes and is subject to change over the geologic time-scale. This process is referred to as the Rock Cycle and is illustrated in **Fig. 3**.

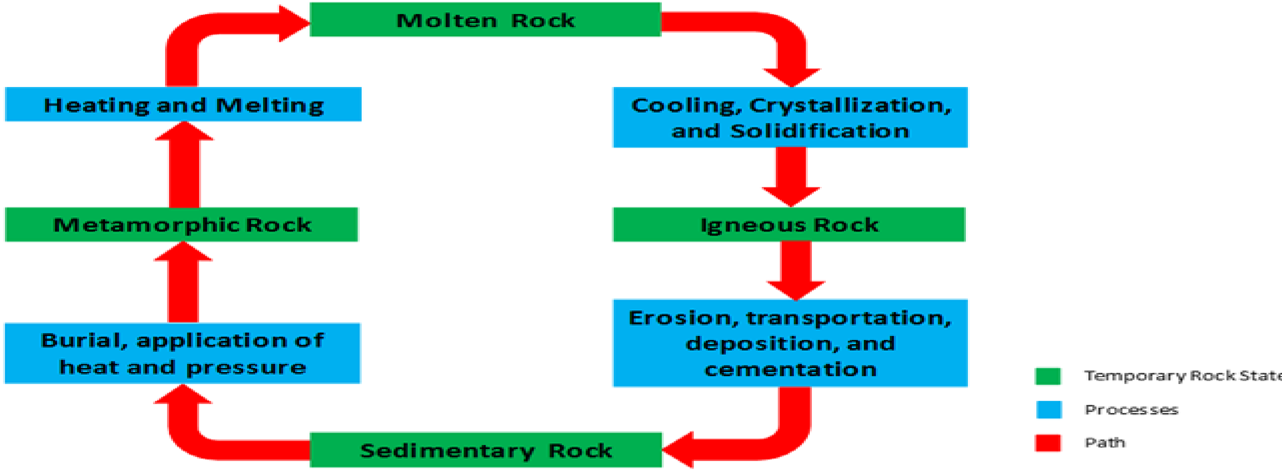


Fig. 3: The Rock Cycle

BASIC PETROLEUM GEOLOGY

The study of the geological processes that create crude oil and natural gas reservoirs is referred to as ***Petroleum Geology***. In this discussion, we will also need to include brief discussions of related, specialized areas of geologic study including *Stratigraphy* and *Structural Geology*.

Stratigraphy is the study of the layers (or *strata*) within rock formations; while **Structural Geology** is the study of the deformation of rock under tectonic forces. You are probably most familiar with the concepts of stratigraphy and structural geology from road-cuts seen along highways. These road-cuts often show cross-sectional outcrops of layered, deformed rock formations along the road-side. The layering you see is the local geologic stratigraphy; while the deformations you see form the local geologic structure of the rock formations.

Hydrocarbon reservoirs are typically associated with sedimentary rock formations. Over geologic time, weathered and eroded rock materials are carried downstream from elevated regions to lower regions in rivers and streams to oceans, seas, or lakes. At the point in the rivers, oceans, seas, or lakes where the energy in the water can no longer suspend or transport the rock material, it begins to settle in the water and is deposited onto the bottom of the water body. This is called the *depositional process*. During the depositional process, the environment can change over the geologic time scale: mountain tops and hilltops erode, sea-levels rise or lower, etc. With these changes, the types of sediments that are deposited change and the locations where they are deposited also change. Two commonalities that exist during the depositional process, even over the geologic time scale, are (1) the sediments and, consequently, the sedentary rocks that are lower in the *stratigraphic column* were deposited earlier than sediments higher in the stratigraphic column and (2) the layers of sediment are initially deposited horizontally. From this discussion, we can see that sediments lower in the *stratigraphic column* must be older than those higher in the stratigraphic column.

There are five geological requirements for the formation of a conventional hydrocarbon reservoir:

1. Source Rock
2. Migration Path
3. Cap Rock
4. Reservoir Rock
5. Trap

These geological requirements are illustrated in **Figure 4** It needs to be emphasized that although this figure consists of solid colored bands, these bands represent either porous or non-porous rocks. In the following discussions, all of the action concerning this figure is occurring in the pore-spaces of porous rock.

In this figure, the ***Source Rock*** is represented by the light grey layer. This is the rock in which the original organic material is converted into hydrocarbons. Hydrocarbons do not necessarily originate in the hydrocarbon reservoir itself but are generated away from the reservoir in rocks that are conducive to hydrocarbon generation. As we will discuss later, these source rocks are typically organic-rich shales, siltstones, or coals.

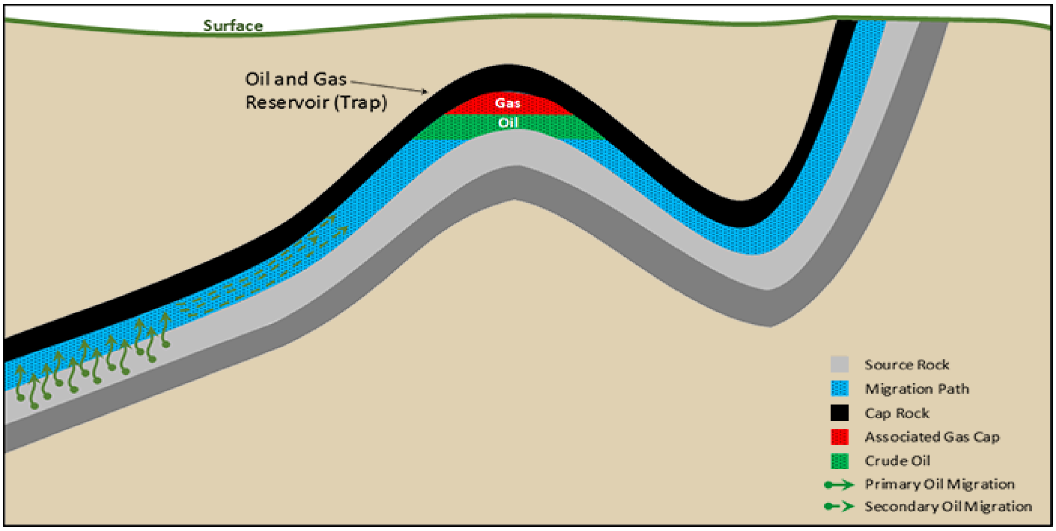


Fig. 4: Typical Oil and Gas Reservoir Showing the Requirements for Conventional Crude Oil and Natural Gas Reservoirs

Since the hydrocarbons are generated away from the reservoir, there must be a pathway for the hydrocarbons to migrate from the source to the reservoir. This pathway is the ***Migration Path*** in the hydrocarbon system. In the example shown in **Figure 4** the migration path is a water-filled rock layer (aquifer) that is in communication with both the source rock the hydrocarbon bearing reservoir. This aquifer is shown as the blue layer in **Figure 4.**

In **Figure 4**, the solid green arrows represent the **primary migration** of the hydrocarbons, while the dashed green arrows represent the **secondary migration** of the hydrocarbons. Primary migration refers to the initial expulsion of the hydrocarbons from the source rock, while secondary migration refers to the remainder of migration to the reservoir.

As shown in this figure, all fluid migration is **upward**. This is because the main driving mechanism in hydrocarbon migration is ***BUOYANCY***, which occurs because the oil and gas are less dense (lighter) than the resident water. In order to prevent this buoyant flow from occurring all of the way to the surface, a vertical flow barrier, or ***Cap Rock***, is required along the migration path and at the reservoir itself. A cap rock is simply an overlying rock layer that is impermeable to flow. ***Permeability*** is a property of the rock that is a measure of the ease in which fluids can flow through a porous medium (in our case, a rock formation). In **Figure 2.06**, the cap rock is depicted by the black layer.

The fourth requirement for a hydrocarbon accumulation is the presence of a Reservoir Rock. In the example shown in **Figure 4**, the reservoir rock is the same rock formation as the migration path. As stated earlier, the most common reservoir rocks are sedimentary rocks; however, naturally fractured igneous and metamorphic rocks can also form hydrocarbon reservoirs. The two requirements for a commercial crude oil or natural gas reservoir are **high *porosity* and high *permeability*.**

The porosity of a rock is defined as the fraction of the rock's bulk (total) volume occupied by the pores. For example, a cubic foot (1 ft^3) of rock with 15 percent porosity will contain 0.15 ft^3 of pore space. Consequently, a rock formation with a higher porosity implies greater storage capacity than a rock formation with a lower porosity. This, in turn, results in the possibility of greater quantities of oil and gas stored in the more porous rock.

Permeability is defined as the ease in which fluids flow through porous media. A high permeability formation implies greater oil and gas production rates and more economically attractive production wells.

The last component of a hydrocarbon system is the *Trap*. A trap or trapping mechanism is a change in the stratigraphy or a structural deformation that is capable of stopping the migration process and keeping the oil and gas in place over geologic time. In the example in **Figure 4** the trap is an ***anticline*** like that shown in the photograph in **Figure 3.**

Statistically, anticlines are the most common traps; however, they are not the only types of hydrocarbon traps. These traps, as they expand, form what is known as reservoirs. A **"reservoir**" is defined as an accumulation of oil and/or gas in a porous and permeable rock - almost invariably of sedimentary origin.

TYPES OF HYDROCARBON TRAPS

Nomenclatures of a Trap

Many terms are used to describe the various parameters of a trap. These terms are defined as follows, and illustrated with reference to an anticline trap – the simplest type of a trap.

1. **The crest or culmination**: the highest point of a trap.
2. **Spill point**: the lowest point at which hydrocarbons may be contained in the trap.
3. **Closure of the trap**: the vertical distance from the crest to the spill point; this lies on a horizontal contour, the spill plane.
4. **The pay:** the productive reservoir within a trap.
5. **Net pay:** the vertical thickness of the productive reservoir.
6. **Gross pay:** the vertical distance from a reservoir to the oil: water contact (OWC).
7. **The oil : water contact** (OWC): the deepest level of producible oil. Similarly the gas:oil contact (GOC) or gas : water contact (GWC): the lowest limit of producible gas

Hydrocarbon traps are categorized into:

i. Structural traps.
ii. Stratigraphic traps.
iii. Combination traps.
iv. Diapiric traps.
v. Hydrodynamic traps.

A. STRUCTURAL TRAPS

Those traps whose geometry was formed by tectonic processes after the deposition of beds involved, i.e., are related to mechanical deformations and failures of the reservoir rock. Basically, structural traps are caused by **folding** or **faulting**. Sometimes it's possible to find a trap where a single process took place, but frequently the two processes can be involved with equal importance in the creation of trap. Structural traps are divided into:

1. Fold (anticline) traps.

2. Fault traps.

1. Fault Trap

A fault trap is created when a rock formation undergoes mechanical failure during an earthquake and the resulting fault causes a porous and permeable rock formation (**reservoir rock**) to be positioned adjacent to an impermeable rock formation as seen in **figure 5b.** Thus, **closure** to the trap is formed by the cross-fault impermeable layer. In some cases, there can be an impermeable substance smeared along the fault line (such as clay) that also acts to prevent migration. This is known as **clay smear.**

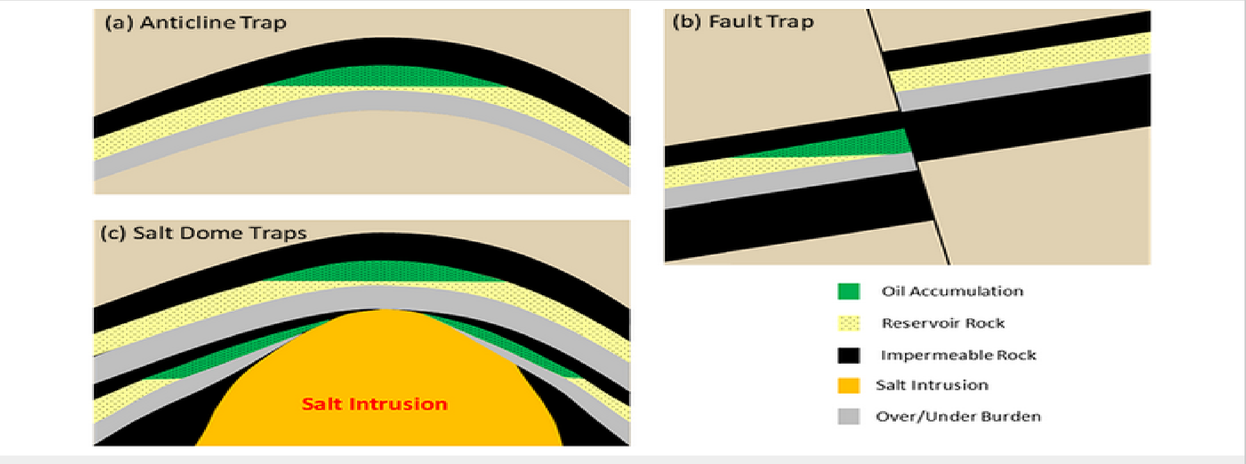


Fig. 5: Structural Traps Resulting in Crude Oil and Natural Gas Accumulations

2. Anticline (Fold) Traps:

An anticline is an area of the subsurface where the strata have been pushed into forming a domed shape. If there is a layer of impermeable rock present in this dome shape, then hydrocarbons can accumulate at the crest until the anticline is filled to the spill point – the highest point where hydrocarbons can escape the anticline. Anticline traps are usually long oval domes of land as sen on **Figure 5a.**

3. Salt Dome Traps

These traps are common in areas where salt formations exist, such as in the Gulf of Mexico. Since large volumes of salt behave in a plastic manner over geologic time, the weight of the overburden creates great pressures within the salt causing it to flow through any local weak spots in the overburden. These salt intrusions can create hydrocarbon traps above and to the flanks of the intrusion as depicted in **Figure 5c**.

B. STRATIGRAPHIC TRAPS:

Traps have a geometry that is formed by changes in **lithology**. The lithological variations may be depositional (channels, reefs, and bars) or post depositional (truncations and digenetic changes). Levorsen (1934) defined a **stratigraphic trap** as " one in which chief **trap-making element** is some variation in stratigraphy, or lithology, or both, of the reservoir rock, such as facies change, variable local porosity and permeability, or an up-structure termination of the reservoir rock".
Stratigraphic traps are divided into:

1. Pinchout traps: oil and gas are trapped where a layer of reservoir rock ends in a wedge surrounded by impermeable rocks. A pinchout trap as seen on **Figure 6a**, is formed due to the relative rise and fall of a water body in relation to the local land mass. (Note: **a relative rise or fall may be due to either a true rise or fall of the sea level, or a subsidence or uplift of the land mass.)** In this figure, the crude oil reservoir is represented by the green area encased in the black, impermeable layer. As mentioned earlier in this lesson, the size and weight of the sediments that form sedimentary rocks are deposited in water are dependent on the energy of the water suspending the particles. Heavier, coarser materials can only be suspended in high energy environments near the shore where wave and tidal action keep these materials mixed with the water. These materials are deposited as sediments at the point in the depositional environment where the wave and tidal energy can no longer support them. On the other hand, lighter, finer sediments can be suspended in low energy environments away from the shore in more calm waters and, consequently, are deposited further from the shoreline. As the relative position of the sea level changes over the geologic time scale, the positions of the coarser and finer sediments change. The coarser materials with the larger pore spaces between the sediment grains often make good quality rock, while the finer materials, particularly clays and silts, with smaller pore spaces make good impermeable seals (cap rocks). Under the proper sequence of events, as the geographical locations of the sediments change over the geologic time scale, the changes in the size of the sediments can create pinchout, or stratigraphic trap.

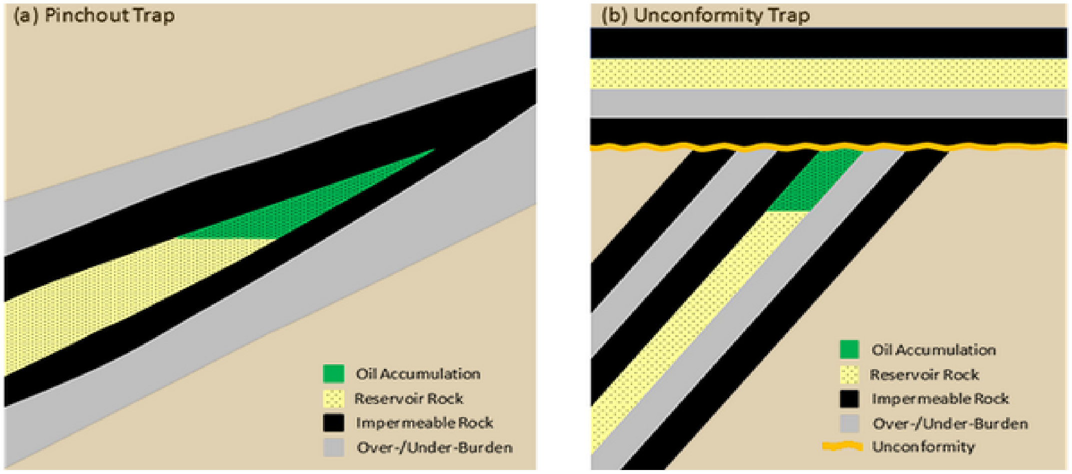


Figure 6: Stratigraphic Traps Resulting in Crude Oil and Natural Gas Accumulations

2. Unconformity traps: have been formed due to break in the depositional sequence of sediments. A geological unconformity is a boundary between two rock sequences of different ages that are missing some transitory rock sequences of intermediate ages - in other words, some rock strata are missing from the local geological record. This gap in the geological record is caused by a past erosional period.

The depositional history of an unconformity trap is slightly more complicated than that of a pinchout trap. In this trap system, an early depositional period caused sedimentary rocks to be deposited horizontally. These rocks were then tilted due to local tectonic forces. These form the lower tilted layers in **Figure 6b**. The higher, uplifted portions of the tilted layers were then eroded over geological time. The orange wavy line represents an *unconformity surface* where rocks are missing from the geological record. Geologists recognize these unconformity surfaces when they see rocks of one age sitting on top of rocks of a different age with no intermediary age rocks between them; while *paleontologists* recognize unconformities by rocks containing fossils from one age sitting directly on top of rocks containing fossils from a different, much older age. After subsidence, a second depositional period occurs where additional sedimentary rocks are again deposited horizontally over the erosional surface. In order for an unconformity trap to develop, the first layer deposited during the second depositional period must be an impermeable rock which can act as the cap rock for the reservoir. After the second depositional period, the trap can be charged with crude oil to form the oil reservoir - the green area of the figure. (Note that the horizontal yellow layer representing good quality reservoir rock above the unconformity surface, does not contain crude oil or natural gas. This is because it is missing a trapping mechanism at this location.

3. Isolated, lenticular bodies: commonly of sandstone, form closed traps. Some of them are produced because they are filled with oil without free water. Most of them are small ex: channels and bars.

4. Massive traps: consists of reef traps and massive erosion traps.

C. DIAPIRIC TRAPS

Where salt or mud have moved upward and domed the overlying strata. They can be considered as structural traps, but since they are caused by local lithostatic movement not regional tectonic forces they should be differentiated. They are classified into:

1. Salt diapirs (Domes).

2. Mud diapirs.

Salt Diapirs: Masses of salt are pushed up through clastic rocks due to their greater buoyancy, eventually breaking through and rising towards the surface. This salt is impermeable and when it crosses a layer of permeable rock, in which hydrocarbons are migrating, it blocks the pathway in much the same manner as a fault trap. This is one of the reasons why there is significant focus on subsalt imaging, despite the many technical challenges that accompany it.

Mud Diapirs: just like in the formation the formation of salt domes, mud diapirs formation are aided by the upward buoyancy of gas-charged muds, especially during volcanism, where overpressure builds up due to gravitational or fluid loading, leading to gas migration via faults and fractures. Here a combination of overpressure and the buoyancy of expanding gas drive the flow.

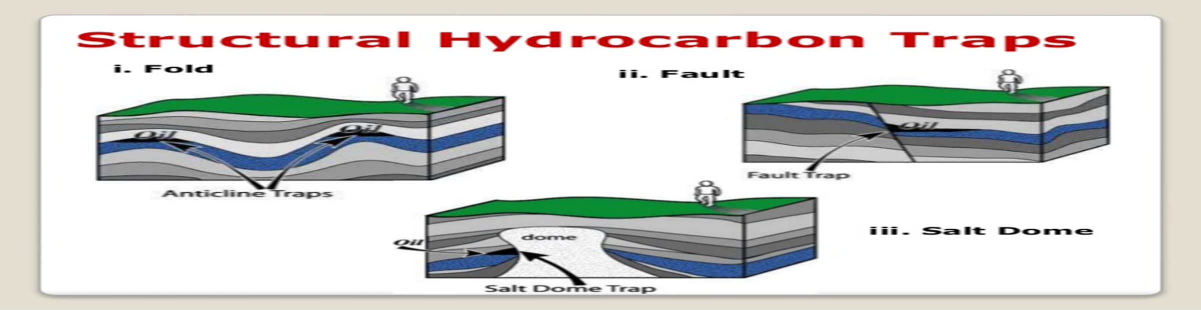


Figure 7

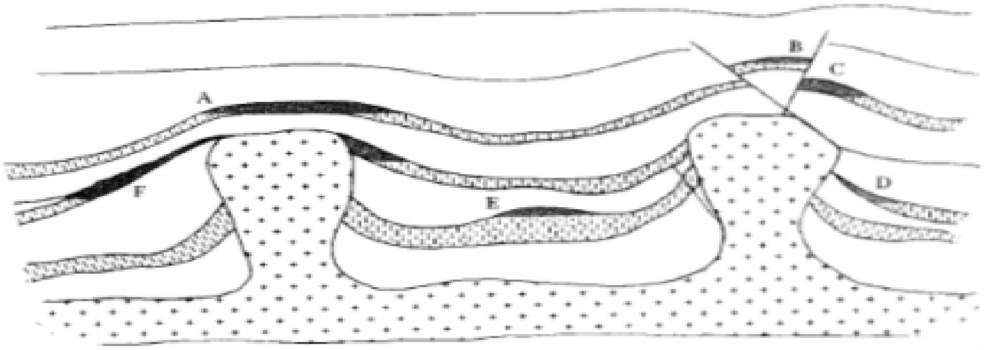


FIGURE 7.24 Crustal cross-section illustrating the various types of trap that may be associated with salt movement: (A) domal trap, (B and C) fault traps, (D) pinchout trap, (E) turtle-back or sedimentary anticline, and (F) truncation trap.

Figure 8

Hydrodynamic traps:

Occurs when downward movement of water prevent the upward movement of oil, thus trapping the oil without normal structural or stratigraphic closure. Such traps are very rare.

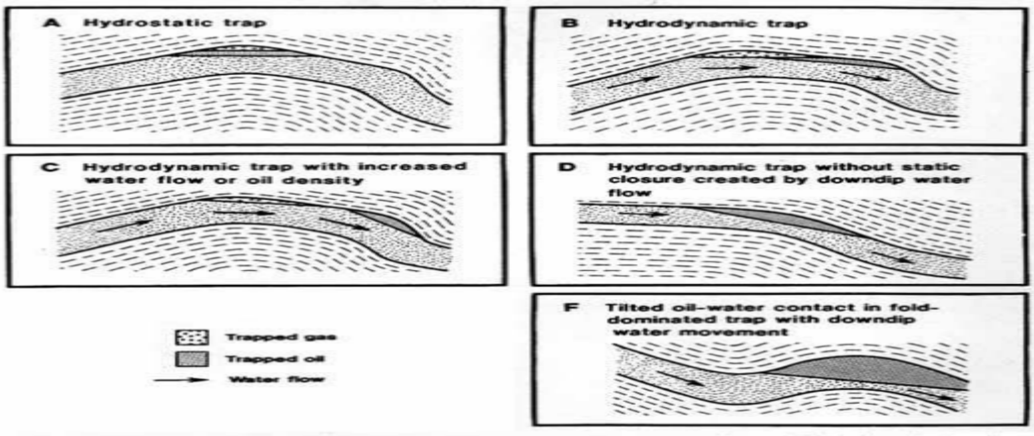


Figure 13.11. Illustrations of the qualitative effect of the amount and direction of water flow and oil density on hydrocarbon trap configuration. (A) Generalized hydrostatic trap. (B) Generalized hydrodynamic trap. (After Hubbert, 1953; North, 1985.) (C) Hydrodynamic trap with increased water flow or oil density. (D) Hydrodynamic trap without static closure created by downdip water flow. (E) Same situation as in (D) but with updip water flow. (F) Tilted oil–water contact in fold-dominated trap with downdip water movement. (G) Tilted oil–water contact in fold-dominated trap with updip water movement.

Figure 9

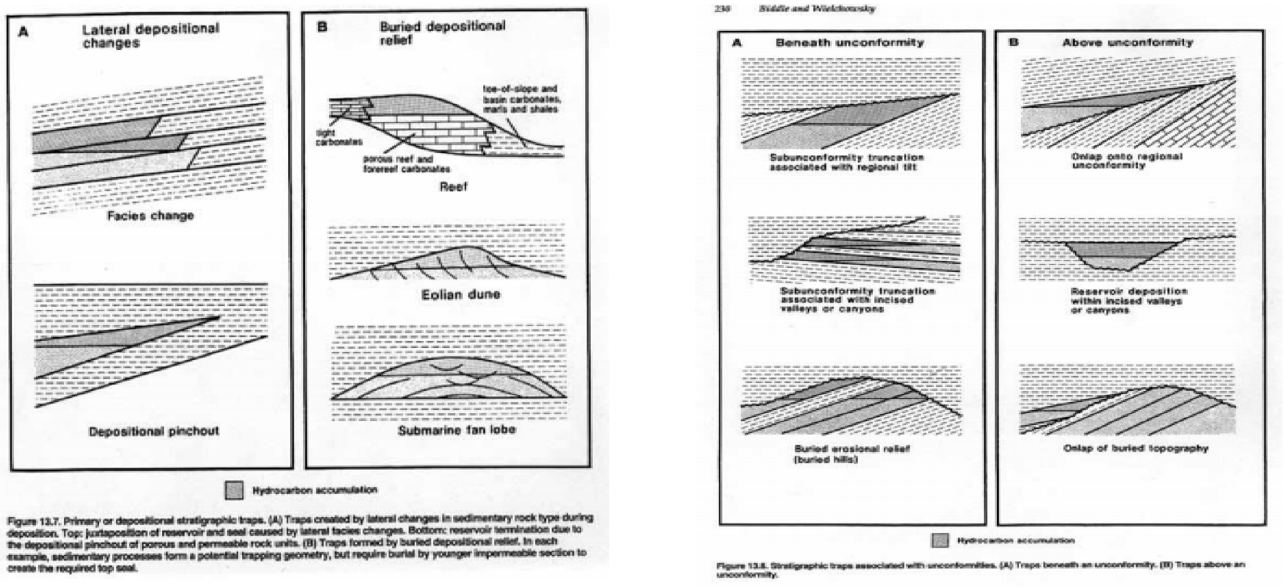


Figure 13.7. Primary or depositional stratigraphic traps. (A) Traps created by lateral changes in sedimentary rock type during deposition. Top: juxtaposition of reservoir and seal caused by lateral facies changes. Bottom: reservoir termination due to the depositional pinchout of porous and permeable rock units. (B) Traps formed by buried depositional relief. In each example, sedimentary processes form a potential trapping geometry, but require burial by younger impermeable section to create the required top seal.

Figure 13.8. Stratigraphic traps associated with unconformities. (A) Traps beneath an unconformity. (B) Traps above an unconformity.

Figure 10

Combination traps:

Many oil and gas fields around the world are not due to structure or stratigraphy or hydrodynamic flow, but a combination of two or more of these forces. Such fields may be termed as combination traps. Most of these traps are caused by a

Generation of Hydrocarbons and Their Migration

Petroleum and natural gas are naturally occurring substances composed of *hydrocarbon molecules* (molecules made up of hydrogen and carbon atoms) and, possibly, non-organic contaminants, such as CO_2, H_2S, N_2, and O_2.

The most widely accepted theory of the origin of petroleum and natural gas is the *Organic Origin Theory* which states that these fluids are generated from the decay of prehistoric plants and animals under the influence of the excessive pressures and temperatures that exist in the earth's subsurface. Research indicates that petroleum and natural gas originated from zooplankton (single-celled plants found drifting freely in fresh or brackish water) and algae. During their lifetimes, these organisms create energy from photosynthesis to carry out their life processes, and it is this energy that we use today (thus the term, "fossil fuels"). Contrary to the popular myth, petroleum and natural gas **do not** originate from decomposed dinosaurs.

Over the geologic time scale, these free-floating zooplankton and algae die, settle to the ocean-, sea-, lake , river , or swamp-bottom, and accumulate as sediment. This process occurs simultaneously with the geological processes (erosion, transportation, and deposition) acting on the sand, silt, and clay sediments that form sedimentary rocks. As the organic material and rock materials accumulate on the sea bottom, the materials at the top of the accumulation exert increased weight (pressure) on the materials at the bottom of the accumulation. As this depositional process continues and the accumulation becomes thicker, the impact of the earth's geothermal gradient also begins to act on the organic materials. At elevated pressures and temperatures, the decaying organic materials are transformed into a dark waxy material called kerogen. Kerogen is an intermediary stage in the development of petroleum. The process of converting the original organic material into kerogen is called the *Catagenesis Process*. The formation of kerogen requires that the rock containing the original organic material be impermeable. This requirement is essential because as kerogens are formed, they must remain trapped within the pore-spaces of the rock and cannot be allowed to escape to other rock formations or to the environment. As we have already discussed, the rock formation in which the original organic materials are converted to kerogen, and eventually petroleum, are called *source rocks* for the hydrocarbons. Typically, fine-grained, clay-rich sedimentary rocks, such as shales, are the most common source rocks for hydrocarbon basins because they satisfy two of the requirements for kerogen generation; they (1) are sedimentary rocks and (2) contain adequately low permeabilities.

During the catagenesis process, the kerogen is "cooked" in the high-temperature environment, and the long-chain kerogen molecules are "cracked" into shorter-chained hydrocarbon molecules. It may take several million years for the deposition process to bury the original organic materials and the source rock to achieve the appropriate temperatures (> 250 - 300 ºF) for kerogen generation and another several million years to generate commercial quantities of oil and gas. There is a specific temperature range, referred to as the "oil window," in which oil is formed. At temperatures below the oil window, the catagenesis process cannot occur; while at higher temperatures the "cooking" and "cracking" processes are stronger and very short-chain natural gas molecules are generated (thermogenic gas).

A second, less accepted theory for the origin of hydrocarbons is the ***Inorganic* or *Abiogenic*** *Theory*. In this theory, hydrogen and carbon from inorganic sources are fused at the elevated pressures and temperatures in the Earth's subsurface and are converted to hydrocarbons. While the presence of inorganically sourced hydrocarbons cannot be discounted, there is abundant evidence that the vast majority of crude oil and natural gas have an organic origin.

Figure 11 provides a qualitative illustration of how the evolution of hydrocarbons in the source-rock depends on *temperature* (which is a function of depth), and *time.* The older and deeper the source rock, the greater the likelihood of light oil or gas being formed (the limiting case being pure methane): this is why, historically, deep exploration has found a preponderance of dry gas reservoirs.

Compaction of the deeper sediments beneath the overlying load causes the expulsion of some of the fluid (water and hydrocarbons) from the pore spaces of the source-rock. In this **primary migration** phase, movement is towards more permeable strata in contact with the source rock. The effect of time and temperature (and therefore depth) on the generation of hydrocarbons gaseous hydrocarbons migrate in solution in the water, it is not clear whether the oil phase forms a micro-emulsion with the water, or is in solution.

Given a suitably porous and permeable path through adjacent strata, the **hydrocarbons and water** will flow in the direction of the **maximum hydrostatic potential gradient** - this is the secondary migration phase. Since the hydrocarbons are of a lower density than water, gravitational forces cause them to segregate up-dip.

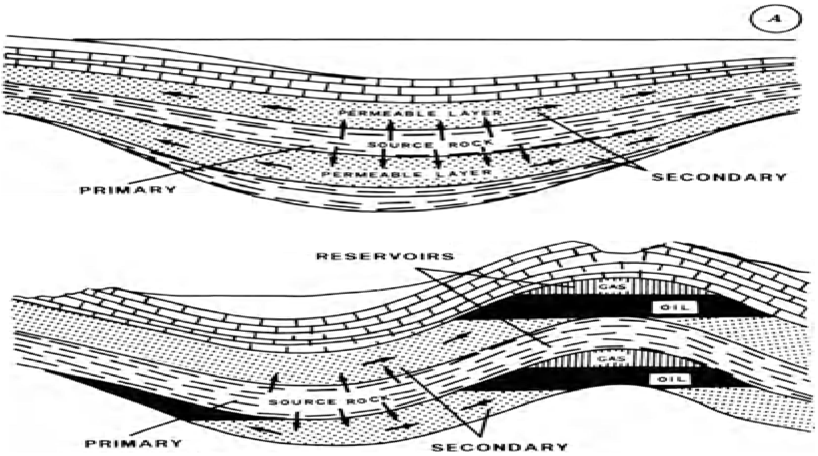


Figure 11 Formation of a hydrocarbon reservoir. A: initial stages of primary and secondary migration. B: advanced stage of hydrocarbon accumulation.

RESERVOIR ROCK AND FLUID PROPERTIES

A. Reservoir Rock Properties

The reservoir rock properties that are of most interest to development geologists and reservoir engineers (amongst others) are *Porosity*, *Compressibility*, and *Permeability*

1. POROSITY

Porosity is a rock property that defines the **fraction** of the **rock volume** that is occupied by the **pore volume.**

Porosity, **ɸ**, is the fraction of the *Bulk Rock Volume*, ***Vb***, that is occupied by the *Pore Volume*, *Vp*

Mathematically, it is defined as:

$$\phi = V_p / V_b$$

The bulk volume, V_b, can also be defined as the sum of the volumes of the two constituents of the rock, pore volume and *Grain Volume*, V_g. That is:

$$V_b = V_p + V_g$$

From these two expressions, we can develop several equivalent definitions for porosity:

$$\Phi = \frac{V_p}{V_b}$$

$$\Phi = \frac{V_b - V_g}{V_b}$$

Figure 12 (below) shows the porosities for three different idealized grain packings. In this figure, the **rock grains are the spheres** and the **pore volume is the space between the**

spheres.

Note that the porosities of these three systems are independent on the radii of the grains. In a real rock, the grains would be angular (if quartz grains in sandstones) and some of the void space might be filled with smaller grains, mineral cementation, and clays.

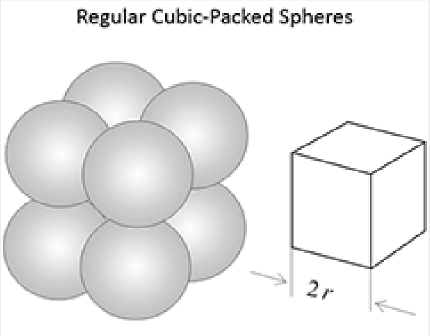
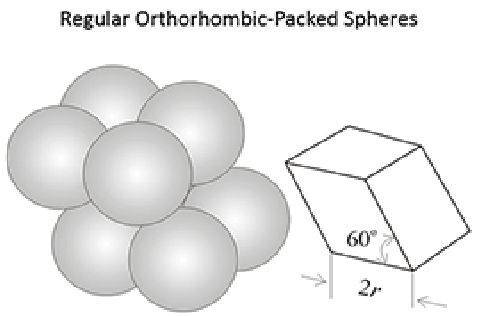
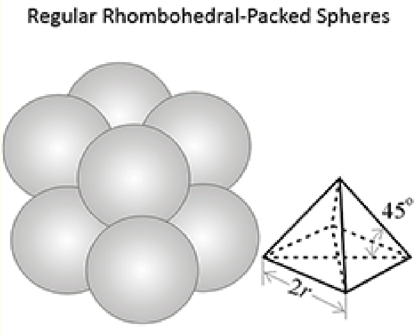
	$\phi=\frac{V_b-V_g}{V_b}=1-\frac{\pi}{6}=0.467$ $V_b=(2r)^3$ $V_g=8\left[\frac{1}{8}\left(\frac{4}{3}\pi r^3\right)\right]=\frac{4}{3}\pi r^3$
	$\phi=\frac{V_b-V_g}{V_b}=1-\frac{\pi r^3}{3\sqrt{3}r^3}=0.395$ $V_b=(2r)\,(2r)\,[r\ \sin(60)]=4\sqrt{3}r^3$ $V_g=\frac{4}{3}\pi r^3$
	$\phi=\frac{V_b-V_g}{V_b}=1-\frac{4\pi r^3}{3\sqrt{3}r^3}=0.260$ $V_b=(2r)\,(2r)\,(h)=4\sqrt{2}r^3$ $h=\sqrt{4r^2-2r^2}=\sqrt{2}r$ $V_g=\frac{4}{3}\pi r^3$

Figure 12: Porosities for Three Different Idealized Grain Packings

There are two types of porosities: they are ***Total Porosity,*** ϕ_t, and ***Effective Porosity,*** ϕ_e.

Real reservoir rock is comprised of connected pores and isolated pores. **Connected pores** are pores which are connected to other pores and are capable of transmitting fluids, whereas, **isolated pores are pores**, or groups of pores, which do not connect to other pores or form dead-end pathways. These isolated pores are **not capable** of transmitting fluids.

Total porosity is defined as the total pore space (connected plus isolated pores) divided by the bulk volume.

Effective porosity is the connected pore volume divided by the bulk volume.

Reservoir engineers are concerned with how fluids are stored and flow in the reservoir. Consequently, reservoir engineers are more concerned with effective porosity, ϕ_e

There are two ways that oil and gas professionals can obtain measurements of porosity, they are:

a. Laboratory measurement and,
b. Use of *Well Logs*.

Laboratory Measurement

Well Logs Measurement

This is the most common method of determining rock porosity. Well logs are tools sent down the wellbore during the drilling process which measure different reservoir properties of interest to geologists and engineers. The three open-hole logs used to evaluate porosity are:

- **The Sonic log:** The ***Sonic Log*** measures the **acoustic transit time, Δt,** of a compressional sound wave traveling through the porous formation. The logging tool consists of one or more transmitters and a series of receivers. The transmitters act as sources of the acoustic signals which are detected by the receivers. The time required for the signal to travel through one foot of the rock formation is the acoustic transit time, Δt. The acoustic travel time, then, is the reciprocal of the sonic velocity through the formation. The units of Δt are micro-seconds/ft (μsec/ft) or millionths of a second per foot.
- **The Density log:** The **Density Log** measures the electron density ρ_e, of the formation (the electron density is the number of electrons per unit volume). The density logging tool emits gamma rays from a chemical source which interact with the electrons of elements in the formation. Detectors in the tool count the returning gamma rays. These returning gamma rays are related to the election density of the elements in the formation.
- **The Neutron log:** The ***Neutron Log*** measures the amount of hydrogen in the formation being logged. Since the amount of hydrogen per unit volume is approximately the same for oil and water, the neutron log measures the *Liquid Filled Porosity* (the porosity excluding the *Gas-Filled Porosity*). The element in the formation with the mass closest to a neutron is hydrogen. Due to the parity in mass, the neutron in a neutron-hydrogen collision loses approximately half of its

energy. With enough collisions, the neutron eventually loses enough energy and is absorbed by the hydrogen nucleus and a gamma ray is emitted. The neutron logging tool measures these emitted gamma rays.

While none of these logs measures porosity directly, the porosity can be calculated based on theoretical or empirical considerations. The measurements obtained from these logs are not only dependent on the porosity but are also dependent on other rock properties such as:

- ***Lithology*** (rock type: sandstone, limestone, shale, etc.)
- The fluids occupying the pore spaces
- The wellbore environment (type of drilling fluid, hole size)
- The geometry of the pores.

2. ROCK (PORE-VOLUME) COMPRESSIBILITY

This is how the pore-volume behaves (increases or decreases) with increases or decreases in pore-pressure.

The isothermal pore-volume compressibility is always positive and is defined as:

$$CPV = \frac{1}{Vpv} \frac{dV_{PV}}{dp} \Big]_{T constant.}$$

The units of compressibility are 1/psi. The equation above implies that as pressure increases the pore-volume increase.

3. ROCK PERMEABILITY

The permeability of a porous medium is a measure of the ease (or difficulty) in which a fluid can flow through the pores of the medium. Permeability is a property of the porous medium which in our case is the reservoir rock. The unit of permeability is the *Darcy*, or D, named after the French engineer Henri Darcy who investigated the flow of water through filter beds.

$$q_w = kA \frac{\partial p}{\partial l}$$

Where:

- q_w is the flow rate of water, cc/sec
- k is the permeability of the medium, Darcy
- A is cross-sectional area, cm^2
- l is the length in the direction of flow, ft (x, y, or z in Cartesian coordinates)
- $\frac{\partial p}{\partial l}$ is the pressure gradient, atm/cm

B. Reservoir Fluid Properties

i. Water Properties

➤ Water Formation Volume Factor, Bw

The water (or more correctly, the brine) Formation Volume Factor, Bw, (sometimes referred to as the FVF) is defined as the ratio of the volume of water at reservoir (in-situ) conditions to that at stock tank (surface) conditions. This factor is used to convert the flow rate of water (at stock tank conditions) to reservoir conditions is a pressure and temperature dependent property that relates the volume of 1.0 stock tank barrel, STB, of water to its volume in barrels, bbl, at another pressure.

By definition, if we had 1.0 STB of water at p_{ST} and T_{ST}, and that same STB occupied 1.02 bbls at reservoir conditions, p_r and T_r, then it would have a formation volume factor of:

$$Bw(pr,Tr) = \frac{Vwrbbl}{Vw\ ST\ STB} = \frac{1.02\ \text{bbl}}{1.00\ STB} = 1.02\ bbl/STB$$

➤ Water Isothermal Compressibility, c_w

The compressibility of any substance, e.g. water, is the change in volume per unit volume per unit change in pressure. Water compressibility is a source of energy for fluid flow in a reservoir, but it is only significant when there is no free gas present in the reservoir.

$$c_w = -\frac{1}{V_w}\frac{dV_w}{dp}\Big]_{T=constant}$$

One correlation for water compressibility, c_w, is:

$$c_w = (7.033p + 541.5C - 537.0T + 403.3 \times 10^3)^{-1}$$

➤ Water Viscosity, μ_w

Water viscosity is a measure of the resistance to flow exerted by the water. Higher values indicate more resistance to flow. For water, the viscosity decreases with increasing temperature and increases with increasing pressure. Water viscosity is a very weak function of pressure, and is measured with a viscometer in the laboratory. A correlation given by McCain can be used to calculate the viscosity of water.is as given below:

$$\mu_{w\ 14.7\ psi} = AT^{-B}$$

with

$$A = 109.574 - 8.40564S + 0.313314S^2 + 8.72213 \times 10^{-3}S^3$$

and

$$B = 1.12166 - 2.63951 \times 10^{-2}S + 0.313314S^2 + 6.79461 \times 10^{-4}S^2 + 5.47119 \times 10^{-5}S^3 - 1.55586 \times 10^{-6}S^4$$

Where:

- μw at 14.7 psi is the water viscosity at 14.7 psi and temperature, T °F
- S is the salt concentration in weight percent, Wt%.

Water-Specific Gravity/Density

Water specific gravity is defined as the density of the water divided by the density of water at standard conditions (62.3 lb / ft^3). Water contained in a reservoir is saline and usually has a specific gravity greater than 1.0. A correlation McCain for estimating the water density at reference conditions is as:

$$\rho_{w\ ST} = 62.368 + 0.438603\ S + 1.60074 \times 10^{-9}\ S^2$$

where

- $\rho_{w\ ST}$ is the water density at sock tank conditions, lb/ft^3
- S is the salt concentration in weight percent, Wt%

Dissolved Gas/Water Ratio

The solution gas/water ratio is the amount of gas dissolved in the water. It increases approximately linearly with pressure and is a function of the water and gas composition. Quantitatively, the solubility of gas in water is considerably less than that of gas in oil.

ii. Gas Properties

A gas can be defined as a homogenous fluid of low density and low viscosity, which has neither independent shape nor volume. It expands to completely fill the vessel in which it is contained. The properties of gases differ from liquids mainly because the molecules in gases are much further apart than liquids. The ideal gas law states:

$$pV = nRT$$

This equation has limited practical value since no known gas behaves as an ideal gas. However, this equation does describe the behaviour of most real gases at low pressures and it serves as a starting point to develop equations of states for real gases at elevated pressures. Furthermore, the behaviours of most real gases do not deviate drastically from the behaviour predicted by this equation. By inserting a correction factor (Z) into the ideal gas equation, real gas behaviour can be accurately predicted.

$$pV = ZnRT$$

The correction factor is called the gas compressibility factor; the deviation from ideal gas behaviour.

Gas Gravity

Gas gravity is the molar mass (molecular weight) of the natural gas divided by the molar mass of air (28.94 kg/kmol). It ranges from 0.55 for dry sweet gas to approximately 1.5 for wet sour gas. Petroleum gases typically have a gravity of about 0.65.

The gas gravity affects the calculations of gas viscosity, compressibility, compressibility factor, and solution gas-oil-ratio.

Gas Compressibility Factor

The gas compressibility factor of a natural gas is a measure of its deviation from ideal gas behaviour. The gas compressibility factor is the ratio of the volume actually occupied by a gas at a given pressure and temperature to the volume the gas would occupy at the same pressure and temperature if it behaved like an ideal gas.

$$Z = \frac{V_{actual}}{V_{ideal}}$$

The gas compressibility factor is usually between 0.8 and 1.2, but it can be as low as 0.3 and as high as 2.0. It is used in the calculation of gas pseudo-pressures, and in converting gas volumes and rates from standard conditions to reservoir conditions (and vice-versa). It is sometimes called the super-compressibility factor, and is often confused with the term 'compressibility' (which is the change in volume per unit change in pressure). The gas compressibility factor directly affects the gas compressibility.

Gas Compressibility

The compressibility of a substance is the change in volume per unit change in pressure. The gas compressibility should not be confused with the gas compressibility factor. The gas compressibility is a very strong function of pressure and increases as the pressure decreases. Mathematically, it can be expressed as:

$$c_g = \frac{1}{p} - \frac{1}{Z}\frac{\partial Z}{\partial p}$$

Where p is the specified pressure and Z is the gas compressibility factor at that pressure. Thus, the magnitude of gas compressibility is of the order of 1/p.

Gas Formation Volume Factor

The gas formation volume factor is the gas volume at reservoir conditions divided by gas volume at standard conditions. It is used to convert surface measured volumes to reservoir conditions. Defined below, it is a function of the fluid composition and the pressure/temperature ratio between reservoir (in-situ) and standard conditions (14.65 psia and 519.67 °R or 60 °F):

$$B_g = \frac{V_{reservoir}}{V_{surface}} = \frac{14.65\ T\ Z}{519.67\ p}$$

It is a very strong function of pressure, and a weak function of temperature and gas composition.

Gas Viscosity

Gas viscosity is a measure of the resistance to flow exerted by the gas, and it’s given in units of centipoises (cp). Higher values indicate more resistance to flow. For gas, the viscosity decreases with increasing temperature and pressure. As pressure decreases, gas viscosity decreases. The molecules are simply further apart at lower pressure and move past each other more easily.

Experimental determination of gas viscosity is difficult. Usually, it is not measured but is obtained from correlations, which include corrections for H_2S, CO_2, and N_2. Gas viscosity is used in numerous equations, most notably in the definitions of pseudo-pressure and pseudo-time. Typically, gas viscosity is in the range of 0.015 to 0.03 cp or 15 to 30 micro-Pa-s.

Critical Temperature

Gases can be converted to liquids by compressing the gas at a suitable temperature. As the temperature increases, the kinetic energies of the particles that make up the gas also increase, and the gases become more difficult to liquefy. The critical temperature of a substance is the temperature at and above which vapor of the substance cannot be liquefied, no matter how much pressure is applied. For example, the critical temperature of water is 374°C and carbon dioxide is 31.2°C.

Critical temperature represents the temperature above which distinct liquid and gas phases do not exist. As the critical temperature is approached, the properties of the gas and liquid phases become the same, resulting in one phase known as supercritical fluid. The critical temperature value is used in the definition of reduced temperature ($T_r = T / T_c$) which in turn is used directly in correlations or equations of state to determine various PVT properties of natural gases (e.g. viscosity, compressibility, gas compressibility factor, etc.).

Critical Pressure

The critical pressure of a substance is the pressure required to liquefy a gas at its critical temperature. For example, the critical pressure of water is 217.7 atm and carbon dioxide is 73.0 atm.

Critical pressure represents the pressure above which distinct liquid and gas phases do not exist. As the critical pressure is approached, the properties of the gas and liquid phases become the same, resulting in one phase known as supercritical fluid. The critical pressure value is used in the definition of reduced pressure ($p_r = p / p_c$) which in turn is used directly in correlations or equations of state to determine various PVT properties of natural gases (e.g. viscosity, compressibility, gas compressibility factor etc.).

iii. Oil Properties

Correlations of physical properties of reservoir crude oils are more complicated than those for natural gas because of the many different components they contain. Although most components are hydrocarbons, the larger molecule components can be different chemical classes. These larger heavier components can strongly influence the behaviour of the mixture. Also the mixing rules for liquids are considerably different than those for gases because of the complex nature of hydrocarbon liquids.

There are three main sources for developing key oil properties. These are:

- ✓ Subsurface sampling of the produced fluid at reservoir conditions. This is the best method since the complex mixtures of hydrocarbons make each oil unique. The individual properties can then be determined empirically in a laboratory.
- ✓ Surface sampling at a separator where the rate of flow for each fluid, gas and liquids, is measured along with their respective compositions. These fluids are then recombined in the laboratory at reservoir conditions, and the resulting fluid is used to empirically determine key oil properties.
- ✓ Correlations are often used when only key parameters, such as the density of the produced oil and the volume of solution-gas evolved, are known. Correlations should be used only after being proved/tuned with laboratory measurements for subsurface samples of analogous oils.

Oil Gravity

Oil gravity relates the density of oil to that of the density of water. The oil gravity has a very strong effect on the calculated oil viscosity and solution gas-oil ratio. It has an indirect effect on the oil compressibility and the oil formation volume factor, since these variables are affected by the solution gas-oil ratio.

The American Petroleum Institute (API) developed a specific gravity scale that measures the relative density of various petroleum liquids. API gravity is gradated in degrees on a hydrometer instrument and was designed so that most values would fall between 10° and 70° API.

Usually the oil gravity is readily known. It ranges from 45 °API (light oil) through 20 °API (medium density) to 10 °API (heavy oil). The conversion from API gravity (oil field units) to relative gravity (relative to water) is:

$$\gamma_o = \frac{141.5}{{}^\circ API + 131.5}$$

The conversion of oil relative gravity to oil density is:

$$\rho_o = \gamma_o * \rho_w$$

where: $\rho_w \approx 62.37$ lb·m / ft^3 or 1000 kg / m^3

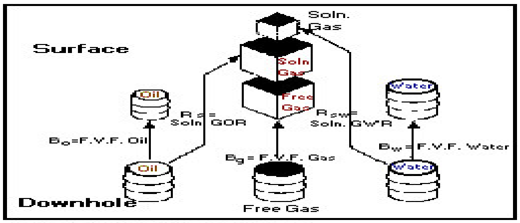
Pour point

Pour point is the highest temperature at which crude oil, chilled under test conditions with a flow plane inclination angle of 45, will not flow after 1min. Crude oil with a high pour point is rich in paraffin

Oil Formation Volume Factor

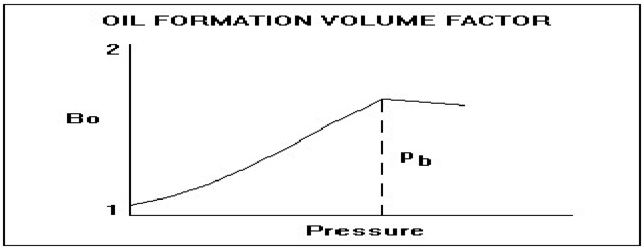
Oil formation volume factor (FVF) is defined as the ratio of the volume of oil and dissolved gas at reservoir (in-situ) conditions to the volume of oil at stock tank (surface) conditions. Since most measurements of oil and gas production are made at the surface, and the fluid flow takes place in the formation, volume factors are needed to convert measured surface volumes to reservoir conditions. It is defined as:

$$B_o = \frac{V_{res}}{V_{surface}}$$



Note: F.V.F. ⟶ Formation Volume Factor

Oil formation volume factor is influenced by two main factors. The dominant factor is solution gas. As pressure increases, the amount of solution gas that the oil can dissolve increases such that the oil swells, and so the formation volume factor exceeds 1.0. Once there is no remaining free gas available to dissolve in the oil, further increases in pressure result in decline in formation volume factor due to the second influencing factor – the compressibility of oil. As shown in the diagram below, oil formation volume factor is dominated by swelling below the bubble point pressure (due to dissolved gas), and by compressibility above the bubble point pressure (since all available gas is now dissolved).



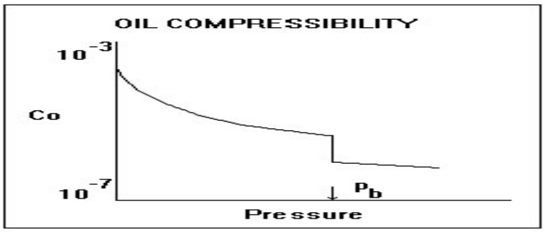
Shrinkage

Shrinkage is the inverse of the formation volume factor for oil, and represents the difference between the volume of oil in the reservoir and its volume when produced to the surface (standard pressure and temperature. The value of shrinkage is generally between 0.5 and 1. The change in volume is due to solution gas coming out of the oil as the pressure decreases.

Oil Compressibility

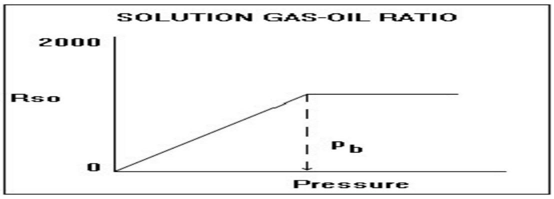
The compressibility of any fluid is defined as the relative change in fluid volume per unit change in pressure. This is usually expressed as volume change per unit pressure. Oil compressibility is a source of energy for fluid flow in a reservoir. In an undersaturated reservoir it is a dominant drive mechanism, but for a saturated reservoir it is overshadowed by gas compressibility effects due to the evolution of dissolved gas. Oil compressibility is a component of total compressibility, which is used in the determination of skin, dimensionless time, and material balance.

Oil compressibility, when plotted versus pressure, shows a significant discontinuity at the bubble point pressure. Above this pressure (undersaturated condition), the oil is a single-phase liquid (consisting of oil and dissolved gas). The compressibility of this liquid can be measured in the laboratory, and it is a weak function of pressure. At and below the bubble point pressure (saturated condition), gas comes out of solution causing a sharp increase in compressibility, which causes the discontinuity shown in the plot. Once below the bubble point, oil compressibility becomes a much stronger function of pressure.



Solution Gas-Oil Ratio

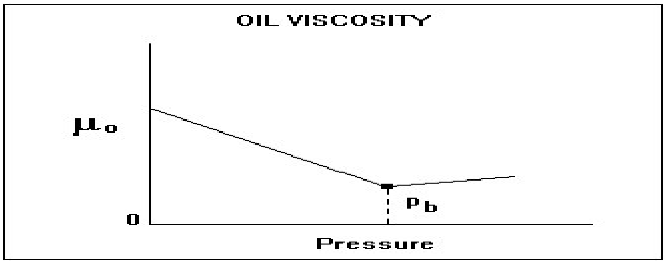
The solution gas-oil ratio is the amount of gas dissolved in the oil at any pressure. It increases approximately linearly with pressure and is a function of the oil and gas composition. A heavy oil contains less dissolved gas than a light oil. In general, the solution gas-oil ratio varies from 0 (dead oil) to approximately 2000 scf/bbl (very light oil). The solution gas-oil ratio increases with pressure until the bubble point pressure is reached, after which it is a constant, and the oil is said to be undersaturated.



The solution gas-oil ratio is a significant component of the PVT correlations. It has a very significant influence on the oil formation volume factor, the oil viscosity, and the oil compressibility.

Oil Viscosity

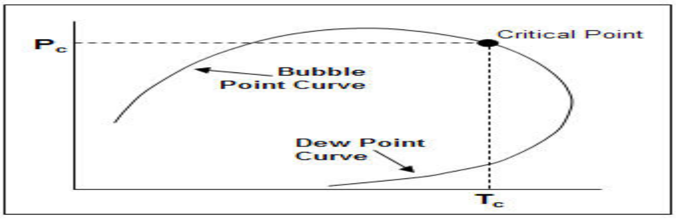
Oil viscosity is a measure of the resistance to flow exerted by the oil, and is given in units of centipoises (cp). Higher values indicate greater resistance to flow. For oil, the viscosity decreases with increasing temperature and pressure (up to the bubble point). Above the bubble point pressure, oil viscosity increases minimally with increasing pressure as shown below. It is a very strong function of reservoir temperature, oil gravity, and solution gas-oil ratio.



The oil viscosity is measured as a function of pressure in most PVT laboratory measurements. Occasionally, a routine oil analysis report will quote the oil viscosity (and the kinematic viscosity). These measurements are at stock tank conditions and should not be used as the in-situ oil viscosity. Dead-oil viscosity is defined as the viscosity of crude oil at atmospheric pressure (no gas in solution) and system temperature. There are several correlations available for estimating oil viscosity at reservoir conditions but great care must be taken since they are very sensitive to the oil gravity and solution gas-oil ratio inputs. The oil viscosity at reservoir conditions can vary from 10000 cP for a heavy oil to less than 1 cP for a light oil.

Bubble Point Pressure

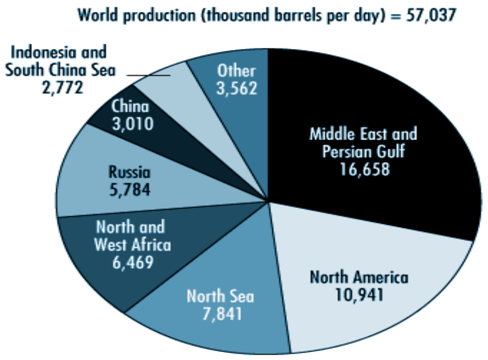
The bubble point pressure is defined as the pressure at which the first bubble of gas comes out of solution. At this point, we can say the oil is saturated - it cannot hold anymore gas. Above this pressure the oil is undersaturated, and the oil acts as a single-phase liquid. At and below this pressure the oil is saturated, and any lowering of the pressure causes gas to be liberated resulting in two-phase flow.



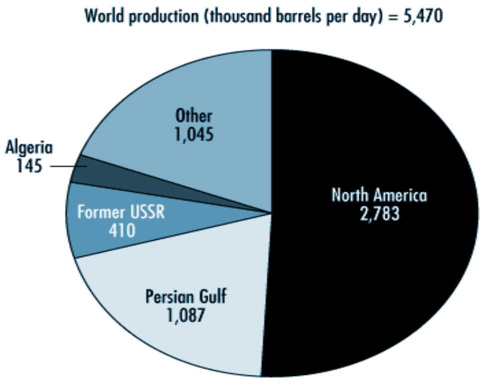
World Distribution of Hydrocarbons

Crude oil and natural gas are found throughout the world, beneath both land and water, as follows:

- ✓ Western Hemisphere Intercontinental Basin (US Gulf Coast, Mexico, Venezuela)
- ✓ Middle East (Arabian Peninsula, Persian Gulf, Black and Caspian Seas)
- ✓ Indonesia and South China Sea
- ✓ North and West Africa (Sahara and Nigeria)
- ✓ North America (Alaska, Newfoundland, California and Mid-continent United States and Canada)
- ✓ Far East (Siberia and China)
- ✓ North Sea



Source: Adapted from Energy Information Administration 1996.



Source: Adapted from Energy Information Administration 1996.

Figs. 12A and B show world crude oil and natural gas production for 1995.

Composition of Crude Oils

Crude oil contains a whole lot mixture of components that when refined separate into distinct constituents for human utilization. Some of them are:

Paraffins: The paraffinic saturated chain type hydrocarbon (aliphatic) molecules in crude oil have the formula CnH2n+2, and can be either straight chains (normal) or branched chains (isomers) of carbon atoms. The lighter, straight chain paraffin molecules are found in gases and paraffin waxes. The branched chain paraffins are usually found in heavier fractions of crude oil and have higher octane numbers than normal paraffins.

Aromatics: Aromatics are unsaturated ring type hydrocarbon (cyclic) compounds. Naphthalenes are fused double ring aromatic compounds. The most complex aromatics, polynuclears (three or more fused aromatic rings), are found in heavier fractions of crude oil.

Naphthenes: Naphthenes are saturated ring type hydrocarbon groupings, with the formula CnH2n, arranged in the form of closed rings (cyclic), found in all fractions of crude oil except the very lightest. Single ring naphthenes (mono-cycloparaffins) with 5 and 6 carbon atoms predominate, with two ring naphthenes (dicycloparaffins) found in the heavier ends of naphtha.

Some non-hydrocarbons present in crude include:

Sulphur and sulphur compounds: Sulphur is present in natural gas and crude oil as hydrogen sulphide (H2S), as compounds (thiols, mercaptans, sulphides, polysulphides, etc.) or as elemental sulphur. Each gas and crude oil has different amounts and types of sulphur compounds, but as a rule the proportion, stability and complexity of the compounds are greater in heavier crude oil fractions. Sulphur compounds called mercaptans, which exhibit distinct odours detectable at very low concentrations, are found in gas, petroleum crude oils and distillates. The most common are methyl and ethyl mercaptans. Mercaptans are often added to commercial gas (LNG and LPG) to provide an odour for leak detection.

The potential for exposure to toxic levels of H_2S exists when working in drilling, production, transportation and processing crude oil and natural gas. The combustion of petroleum hydrocarbons containing sulphur produces undesirables such as sulphuric acid and sulphur dioxide.

Oxygen compounds: Oxygen compounds, such as phenols, ketones and carboxylic acids, are found in crude oils in varying amounts.

Nitrogen compounds: Nitrogen is found in lighter fractions of crude oil as basic compounds, and more often in heavier fractions of crude oil as non-basic compounds which may also include trace metals.

Trace metals: Trace amounts, or small quantities of metals, including copper, nickel, iron, arsenic and vanadium, are often found in crude oils in small quantities.

Inorganic salts: Crude oils often contain inorganic salts, such as sodium chloride, magnesium chloride and calcium chloride, suspended in the crude or dissolved in entrained water (brine).

Carbon dioxide: Carbon dioxide may result from the decomposition of bicarbonates present in, or added to crude, or from steam used in the distillation process.

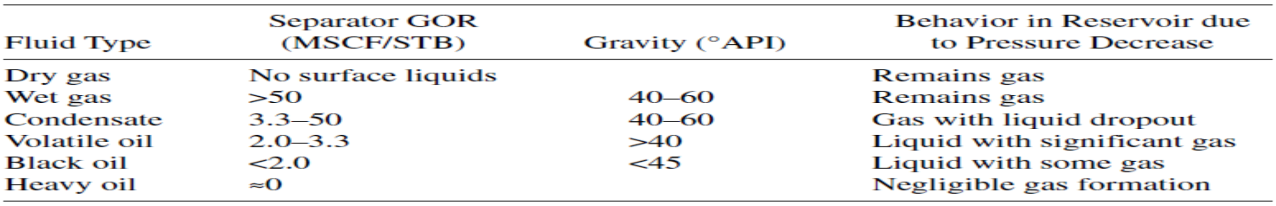
Naphthenic acids: Some crude oils contain naphthenic (organic) acids, which may become corrosive at temperatures above 232 °C when the acid value of the crude is above a certain level.

Normally occurring radioactive materials: Normally occurring radioactive materials (NORMs) are often present in crude oil, in the drilling deposits and in the drilling mud, and can present a hazard from low levels of radioactivity.

Classification of Oil and Gas

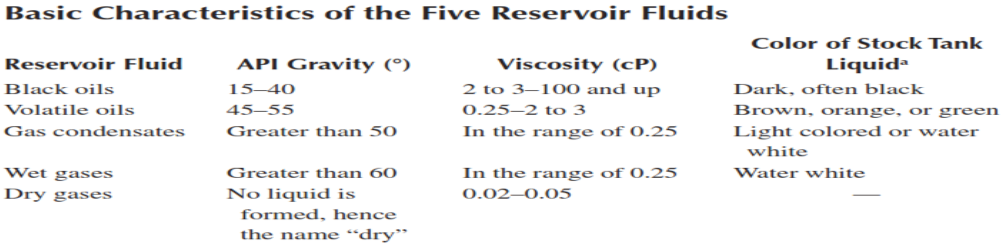
There are a variety of terms for describing hydrocarbon fluids at surface conditions. Natural gas is a hydrocarbon mixture in the gaseous state at surface conditions. Crude oil is a hydrocarbon mixture in the liquid state at surface conditions. Heavy oils do not contain much gas in solution at reservoir conditions and have a relatively large molecular weight. By contrast, light oils typically contain a large amount of gas in solution at reservoir conditions and have a relatively small molecular weight

As a rule of thumb, the following is the classification of oil and gas:



Fluid Type	Separator GOR (MSCF/STB)	Gravity (°API)	Behavior in Reservoir due to Pressure Decrease
Dry gas	No surface liquids		Remains gas
Wet gas	>50	40–60	Remains gas
Condensate	3.3–50	40–60	Gas with liquid dropout
Volatile oil	2.0–3.3	>40	Liquid with significant gas
Black oil	<2.0	<45	Liquid with some gas
Heavy oil	≈0		Negligible gas formation

Fig. 13: Classification of oil and gas.



Basic Characteristics of the Five Reservoir Fluids

Reservoir Fluid	API Gravity (°)	Viscosity (cP)	Color of Stock Tank Liquid[a]
Black oils	15–40	2 to 3–100 and up	Dark, often black
Volatile oils	45–55	0.25–2 to 3	Brown, orange, or green
Gas condensates	Greater than 50	In the range of 0.25	Light colored or water white
Wet gases	Greater than 60	In the range of 0.25	Water white
Dry gases	No liquid is formed, hence the name "dry"	0.02–0.05	—

More technically, hydrocarbons are classed in accordance with their API gravity, where

$$\mathrm{API} = \left(\frac{141.5}{\gamma_o}\right) - 131.5$$

The specific gravity of oil is the ratio of oil density ρo, to freshwater density ρw, which is given by the equation below:

$$\gamma_o = \frac{\rho_o}{\rho_w}$$

EXP: The specific gravity of an oil sample is 0.85. What is its API?

Soln:

$$\mathrm{API} = \frac{141.5}{\gamma_0} - 131.5$$

$$\gamma_0 = {}^{\rho o}/_{\rho w} = 0.865/1 = 0.85$$

$$\mathrm{API} = \frac{141.5}{0.85} - 131.5,$$

API = 34.38

Another way to classify hydrocarbon liquids is to compare the properties of the hydrocarbon liquid to water. Two key properties are viscosity and density. Viscosity is a measure of the ability to flow, and density is the amount of material in a given volume

Liquid Type	API Gravity (°API)	Viscosity (cp)
Light oil	>31.1	
Medium oil	22.3–31.1	
Heavy oil	10–22.3	
Water	10	1 cp
Extra heavy oil	4–10	<10 000 cp
Bitumen	4–10	>10 000 cp

Fig. 14: API Classification of Hydrocarbons

This method is the one of the most-used in petroleum industries to distinguish between the various types of petroleum.

Watson's Characterization

The definitive methods for determining the different components in crude oil are with laboratory measurements, such as gas chromatography. Often, however, less rigorous methods may be useful for quick, on-site evaluations or for numerical (computer) calculations where the crude oil type is characterized with a single parameter. In the oil and gas industry, one common measure of the dominant character of the crude oil (paraffinic, naphthenic, and aromatic) is the Watson Characterization Factor (or a generalization suggested by Whitson).

The original form of the Watson Characterization Factor, K_W, is:

$K_W = T_b^{1/3} Y_o$--*equation 1*

Where:

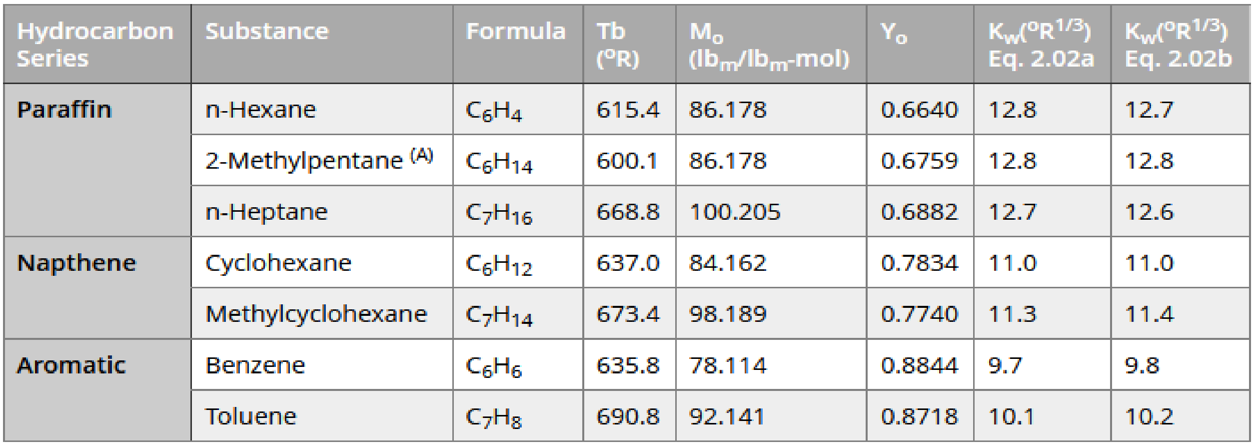
- K_W is Watson Characterization Factor, $^oR^{1/3}$
- T_b is the mean average boiling point of the mixture, ^oR
- Y_o is the specific gravity of the mixture, dimensionless

This equation requires that the boiling point, T_b, for the mixture of interest is known. In many cases, T_b is unknown or difficult to measure. For these cases, Whitson correlated the Watson Characterization Factor with the more commonly known molecular weight:

$K_W = 4.5579 M_o^{0.15178} Y_o^{-0.84573}$-- -*equation 2*

Where:

- K_W is Watson Characterization Factor, $^oR^{1/3}$
- M_o is the molecular weight of the mixture, lb_m/lb_m-mol
- Y_o is the specific gravity of the mixture, dimensionless



Hydrocarbon Series	Substance	Formula	Tb (^oR)	M_o (lb_m/lb_m-mol)	Y_o	$K_w(^oR^{1/3})$ Eq. 2.02a	$K_w(^oR^{1/3})$ Eq. 2.02b
Paraffin	n-Hexane	C_6H_4	615.4	86.178	0.6640	12.8	12.7
	2-Methylpentane $^{(A)}$	C_6H_{14}	600.1	86.178	0.6759	12.8	12.8
	n-Heptane	C_7H_{16}	668.8	100.205	0.6882	12.7	12.6
Napthene	Cyclohexane	C_6H_{12}	637.0	84.162	0.7834	11.0	11.0
	Methylcyclohexane	C_7H_{14}	673.4	98.189	0.7740	11.3	11.4
Aromatic	Benzene	C_6H_6	635.8	78.114	0.8844	9.7	9.8
	Toluene	C_7H_8	690.8	92.141	0.8718	10.1	10.2

Fig 15: Watson's Classification of Reservoir Hydrocarbons

Types of Oil and Gas Reservoirs

An oil and gas reservoir is the oil and gas accumulation in an independent trap with a single pressure system and the unitary gas–oil interface and oil–water interface. In the light of development geology, an oil and gas reservoir has its geometric configuration and boundary conditions, storage and flow characteristics, and fluid properties.

In the classification of reservoirs on the basis of properties of reservoir fluids, we must first introduce the concept of the ***Phase Envelope*** (or, ***Phase Diagram*, or *Pressure-Temperature Diagram*, or *P-T Diagram*)** for single-component (pure) and multi-component (mixture) systems.

THE GIBBS PHASE RULE

The Gibbs Phase Rule relates the degrees of freedom in a system to the number of components and number of phases in a system. The Gibbs Phase Rule is:

$F = C - P + 2$ -- *Equation 3*

Where:

F is the number of degrees of freedom in the system, integer

C is the number of components in the system, integer

P is the number of phases in the system, integer

Degrees of freedom" refers to the maximum number of independent *thermodynamic* variables (pressure, temperature, and *intensive* variables) that you can vary *simultaneously* within a system at equilibrium before you are forced to specify one or more of the remaining variables (or disturb the equilibrium of the system)

"**I*ntensive* variables**" refer to variables that are independent of the size of the system. For example, **phase density** in a system is an ***intensive*** variable because you can halve the size of the system, and the phase density will remain the same. On the other hand, the **mass of a system** is an ***extensive*** property because if you halve the size of the system, then you halve the mass in the system.

A **component** refers an individual chemical element that exists in the system (in our case, a molecular species: methane, ethane, cyclopentane, benzene, CO2, H_2O, etc.).

A ***phase*** is a physical state of matter with homogenous (uniform) composition, physical properties, and chemical properties. In petroleum and natural gas engineering, we typically deal with systems containing four phases: a gaseous hydrocarbon phase (natural gas), a liquid hydrocarbon phase (crude oil), a liquid aqueous phase (water or brine), and a solid rock phase. There are times when we deal with systems containing more phases (such a solid hydrocarbon phase or multiple hydrocarbon liquid phases), which circumstances of occurrence are beyond the scope of this class.

For a single-component system, we have C = 1, and Gibbs Phase Rule becomes:

F=3−P -- *Equation 4*

Plotting the ***phase state*** (number and types of phases) on a pressure-temperature plot for this single-component system, then we would obtain a plot like that shown in Figure 2.09. This figure is also referred to as a *Phase Diagram* or a *P-T Diagram*.

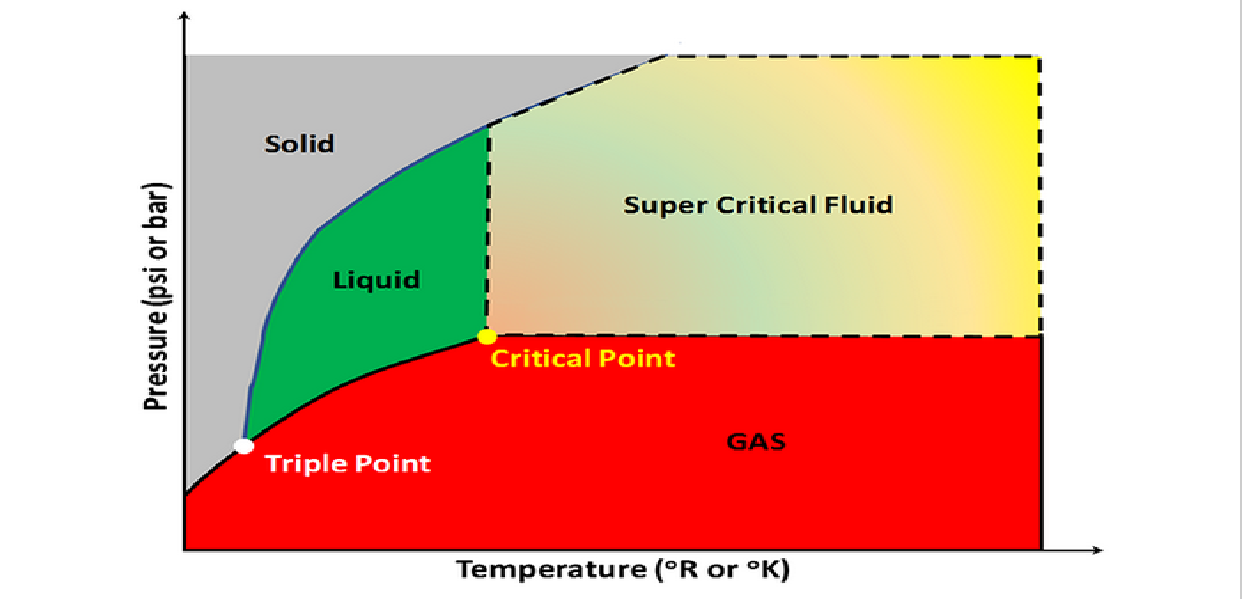


Figure 16: Phase Diagram of a Single Component System (Source: Gregory King).

In this Phase Diagram:

- **Grey region** represents all of the **pressure-temperature combinations** that result in the **solid form of our single component**,
- **Green region** represents the pressure and temperature combinations that result in the **liquid form** of our **single component**,
- **Red region** represents the pressure and temperature combinations that result in the **gaseous form of our single component**, and
- **Multi-colored region** represents the **super critical form of our single component**.

Also posted on this Phase Diagram are two points, the **triple point** and **the critical point**.

Getting back to the single component version of the Gibbs Phase Rule as represented by equation 4, if we consider the single-phase regions in Figure 16 (P = 1 in Equation 4), then from equation 4, we have 2 degrees of freedom (F = 2). This implies that we can **independently vary Pressure** and **Temperature** within the ***Phase Envelope*** (colored regions) and not change the phase state of the system. In other words, two degrees of freedom represent two-dimensional regions (areas) on the Phase Diagram in which a single phase exists.

Now, let's consider the occurrence of two phases coexisting simultaneously (P = 2) in equilibrium. From equation 4 with P = 2, we have one degree of freedom (F = 1). In Figure 16, we have two coexisting phases along the borders of the phase envelopes. For example, the **line bordering the Solid and Liquid Phases** represents the **pressure-temperature conditions** where the solid form of our single component system can coexist with the liquid form of our single component at equilibrium (think of polar caps sitting on water near the earth's poles). For two phases to coexist in equilibrium, if we were to change one variable, say temperature, then we would be forced to change pressure in a manner that it remained on the border line between the two single-phase regions. In other words, one degree of freedom represents the one-dimensional, curvilinear lines which act as borders between the single-phase regions. If we change one variable on one of these border lines, then we are forced to change the other variable to remain on the border line.

Finally, we can consider the coexistence of three phases (P = 3 in Equation 4) in a system at equilibrium. From Equation 4 with P = 3, we have F = 0, or no degrees of freedom. This implies that at the point where three phases coexist (the ***Triple Point*** in Figure 16), we cannot change either pressure or temperature and retain a three-phase system in equilibrium of the single-component (pure) system. The Triple Point is a property of the component that we are considering. Thus, zero degrees of freedom refers to a **0-Dimensional point** (the *Triple Point*)

In Figure 16, the *Critical Point* is also plotted. The Critical Point, defined by the critical pressure, P_c, and the critical temperature, T_c: (P_c, T_c) is the point in the system that defines the onset of the super critical state.

Super critical fluids are fluids in which the gaseous phase becomes indistinguishable from the liquid phase (the **phase densities** become equal).

Consider a pressure-temperature pair in the single-phase gas region with a temperature somewhere between the temperature at the triple point and the critical temperature, T_c, such as **Point A** in **Figure 17,** If we were to increase the pressure of this single-phase gas (**Path A-A'**), then we would see a distinct and abrupt change in the phase state of the fluid as we crossed into the single-phase liquid region. This is because the densities of the gaseous phase and the liquid phase are different. Now, if we were to do the same experiment starting at a temperature greater the critical temperature, T_c, such as **Point B**, then as we increased the pressure on the single-phase gas (**Path B-B'**) and entered the Super Critical Fluid region, there would be no abrupt phase change.

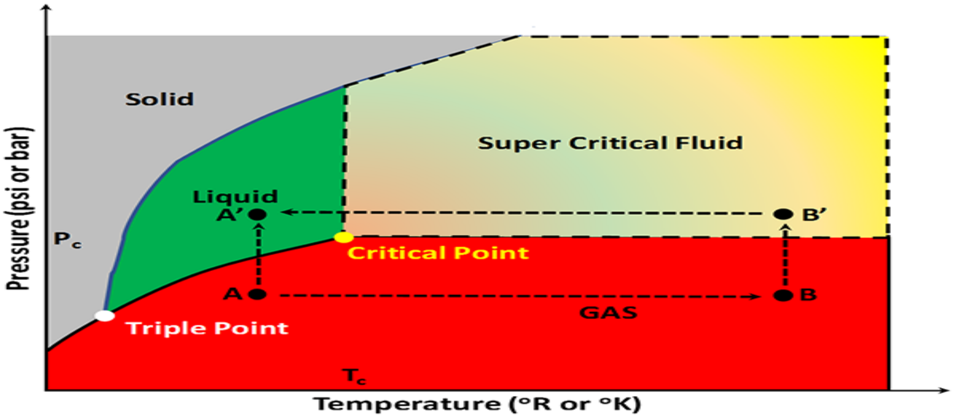


Figure 17: Phase Diagram of a Single Component System Showing the P-T Paths of Three Experiments (Source: Gregory King).

We could also perform a third experiment where we started at the original point, **Point A**, and followed the pressure-temperature path **Path A-B-B'-A'** into the single-phase liquid region to arrive at **Point A'**. In this last experiment, we would arrive at the same point, **Point A'**, as in the first experiment, but without any abrupt phase change. The system properties would change smoothly and continuously during the entire experiment.

For multi-component systems like real crude oil – natural gas systems, the Pressure-Temperature Diagram is much more complex. This is because a real crude oil – natural gas system may contain tens or hundreds of thousands of components. For Multi-Component Systems, the P-T Diagram looks like that in Figure 18. A Phase Diagram, such as that shown in this figure, typically is measured in the laboratory but can also be generated mathematically with sophisticated models, such as, *Cubic Equation of State Equations* (multi-component extensions to van der Waal's Equation).

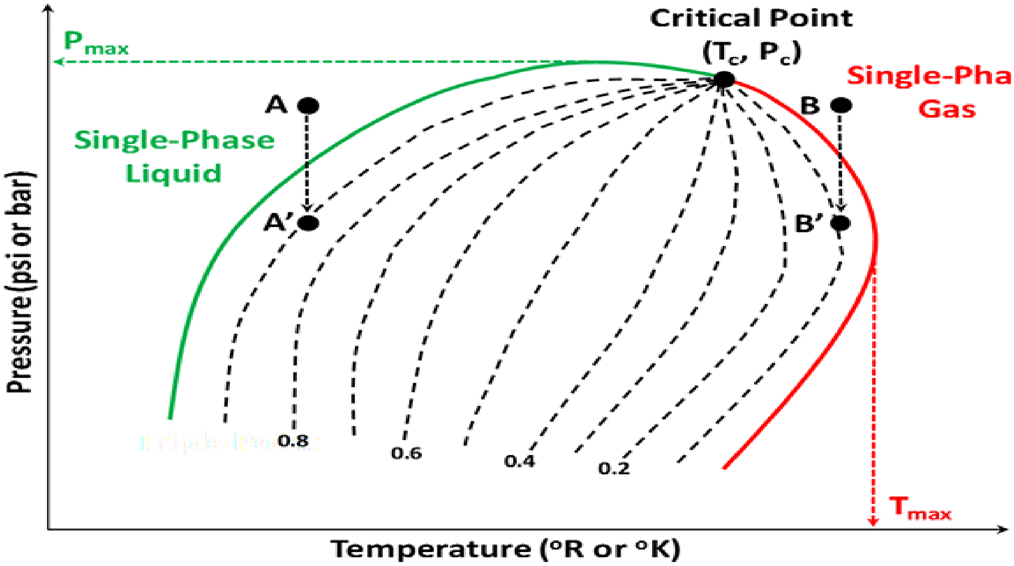


Figure 18: Phase Diagram of a Multi-Component System Typical of Real Hydrocarbon Reservoir Fluids (Source: Gregory King).

In this figure, the region between the green curve and the red curve is the two-phase envelope; while the region outside of the two-phase envelope is the single-phase region. Single-phase liquids exist to the left (lower temperatures) and above (higher pressures) the bubble-point locus (green curve); while single-phase gases exist to the right (higher temperatures) of the dew-point locus (red curve).

The green curve in this figure represents the ***Bubble-Point Locus*** of this multi-component system; the red curve represents the ***Dew Point Locus*** of the system, and the dashed lines in the two-phase region represents the ***quality lines*** of the system (lines of constant volume-fraction of the liquid phase). The bubble-point, defined by a bubble-point pressure, P_b and a bubble-point temperature, T_b, is the point on a pressure-temperature path (originating in the single-phase liquid region) where the path enters the two-phase region (crosses the green curve in Figure 2.11). The name “bubble-point” comes from the fact that this is the point where the first bubble of gas evolved from a liquid as it enters the two-phase region. For example, **Point A** in Figure 2.11 lies in the single-phase liquid region. As the pressure is reduced at a constant temperature (**isothermal conditions**), it follows the **Path A-A’**. The point where **Path A-A’** enters the two-phase region (crosses the green, bubble-point locus) represents the bubble-point pressure for this temperature. This is the point where the first bubble of gas is formed in the system. The pressure reduction is continued until it terminates at **Point A’**. **Point A’** lies on the 0.9 quality line, implying that at this point, the system is composed of two-phases with the liquid phase occupying 90 percent of the volume.

On the other hand, the dew-point, defined by the dew-point pressure and dew-point temperature is the point on a pressure-temperature path (originating in the single-phase gas region) enters the two-phase region. The name dew-point refers to the point where the first liquid drop condenses from the gaseous phase. For example, **Point B** in Figure 18 lies in the single-phase gas region and enters the two-phase region when the pressure is reduced under isothermal conditions (**Path B-B’**). The dew point pressure for this temperature then is the pressure where **Path B-B’** crosses the red dew-point locus. If the isothermal pressure reduction is stopped at **Point B'**, then the system at equilibrium will contain two phases with the liquid phase occupying 10 percent of the system volume.

Finally, the pressure, P_{max} in Figure 18 is the ***cricondenbar*** (the maximum pressure in which two phases can coexist); while the temperature, T_{max} is the ***cricondentherm*** (the maximum temperature in which two phases can coexist).

A. **Reservoir Characterization according to Reservoir properties**

1. Gas Condensate Reservoirs.

Gas condensate reservoirs are gas systems that reside in reservoirs with the original temperatures lying between the critical temperature, TC, and the cricondentherm (Tmax in Fig. 22). If the original reservoir pressure is greater than the dew-point pressure, then a single-phase gas system will occur in the reservoir as in Figure 19.

In this figure, the reservoir is initially a single-phase gas, but as the pressure depletes due to gas production, the pressure-temperature path of the system enters the two-phase region of the phase envelope and liquid hydrocarbons condense from the gas in the reservoir (thus the name gas condensate reservoir.)

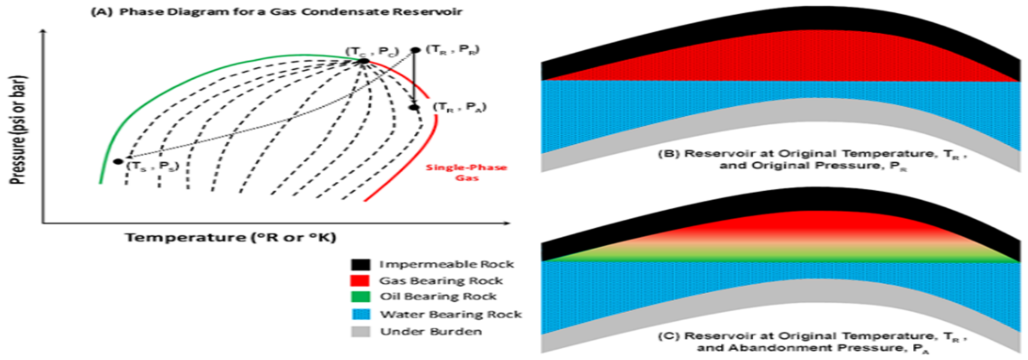


Figure 19: Gas Condensate Reservoirs

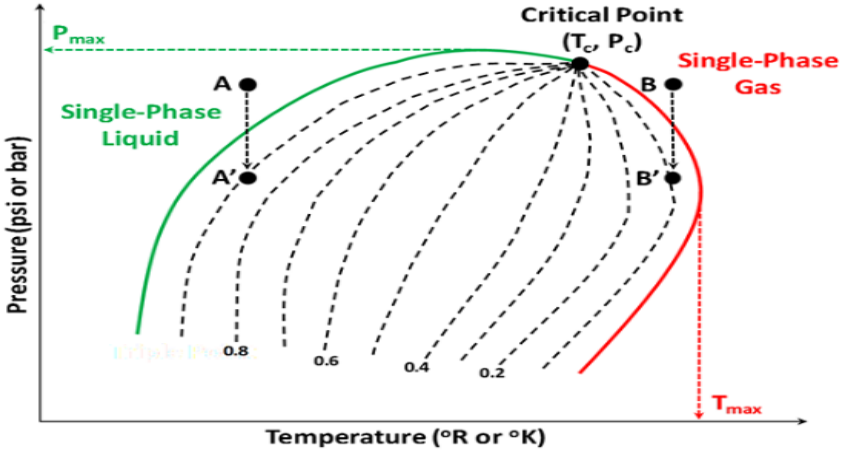


Figure 20: Phase Diagram of a Multi-Component System Typical of Real Hydrocarbon Reservoir Fluids

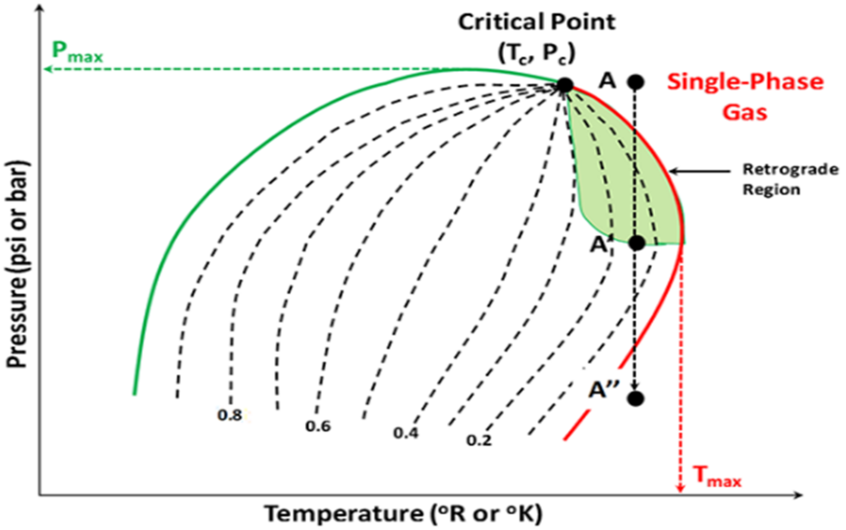


Figure 21: Phase Diagram of a Gas Condensate Fluid Showing the Retrograde Region

Think of a four-component mixture of oxygen, carbon-dioxide, nitrogen, and water vapor (a mixture of air) and its phase envelope. If we started at a point in the single-phase gas region with a pressure below the cricondenbar (Pmax in Figure 20 NOTE FOR CORRECTION) and reduced the temperature under constant pressure conditions (isobaric conditions), then we would cross the dew point locus of the phase envelope. This would be the pressure and temperature where we would see the first dew forming on plants and the first water condensation forming on glass and metal. If we were to continue reducing the temperature, then the percent volume of liquid (water) would increase and it would begin to rain. What is happening in this simple example is that the heaviest component in our system (water vapor) is condensing out of the gas phase (air mixture) and forming a second phase (liquid water) in the two-phase region.

This is essentially what is occurring in the reservoir of a gas condensate system but under isothermal conditions. As we pass through the dew point pressure, the heaviest hydrocarbon components in the system begin to drop out and form a second liquid hydrocarbon phase in the two-phase region of the phase envelope inside the reservoir.

There is one interesting characteristic of gas condensate reservoirs that is worth further discussing and that is the retrograde behavior of these systems. This is illustrated in Figure 21. In this figure, if we were to follow the isothermal Path A-A’-A”, then we would go below through the dew-point pressure, with increase in the volume percentage of the liquid hydrocarbon phase until it reached a maximum at Point A’ with further reductions in pressure resulting in a lower volume percentage of the liquid hydrocarbon phase. We could also continue the isothermal pressure reduction, reenter the single-phase gas region, and stop at Point A”.

From Figures 22 and 23 it is clear that for a pure (single-component) system, the liquid phase occurs at higher pressures than the gas phase. Thus, if we were to start in the single-phase liquid region of a pure system, we would need to reduce the pressure isothermally to create a gas phase.

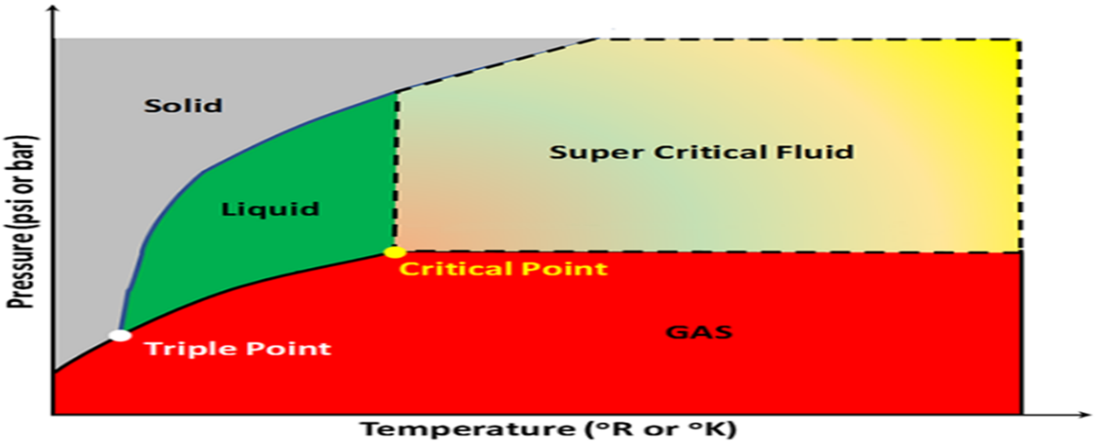


Figure 22: Phase Diagram of a Single Component System

The analogy for our multi-component system is that if we start at the point of maximum liquid volume (Point A’ in Figure 21) and reduced the pressure isothermally, then we would get the conventional behavior for a pure system along Path A’-A”. Conversely, if we were to start at Point A’ and increased the pressure isothermally to Point A in the single-phase gas region, then we would get the behavior opposite of that for a pure system along Path A’-A. This behavior, opposite to a pure system, is referred to as retrograde behavior.

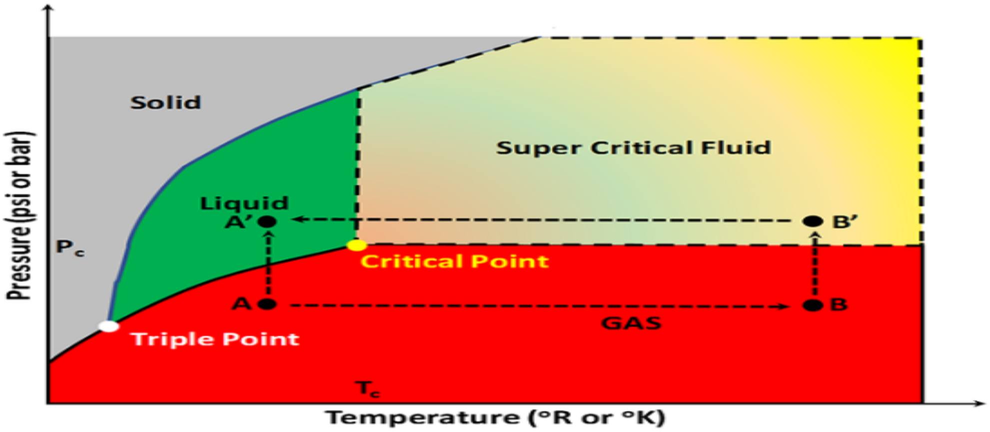


Figure 23: Phase Diagram of a Single Component System Showing the P-T Paths of Three Experiments

This behavior occurs in the green shaded region in Figure 22 This region, formed by connecting all of the points of maximum temperature on the quality lines, is referred to as the retrograde region of the fluid.

2. Undersaturated Volatile Oil (High Shrinkage Oil) Reservoirs

Undersaturated volatile oil reservoirs are single-phase oil systems that reside in reservoirs with an original temperature relatively close to the critical point (relative compared to low shrinkage oils). As with the undersaturated black oils, the term undersaturated implies that the original reservoir temperature and pressure lies in the single-phase liquid region of the phase diagram. Such a system is shown in Figure 26.

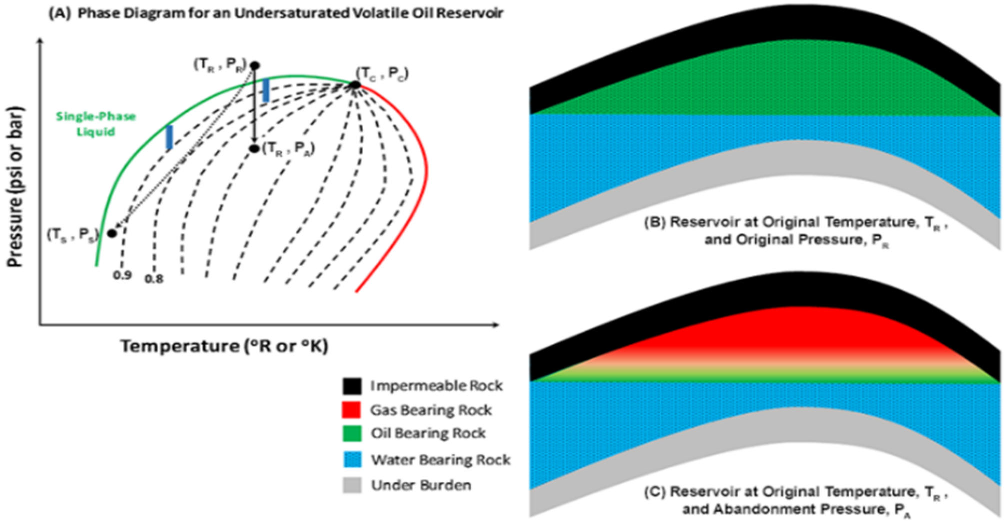


Figure 26 Volatile Oil (High Shrinkage) Reservoirs

To discuss the terms “low shrinkage oil” and “high shrinkage oil” as they pertain to the oil and gas industry, the blue bars on Figure 26 (A) represent equal pressure drops below the bubble-point pressure (these bars are of equal length). We can see from this figure that due to the convergent nature of the quality lines (dashed lines) near the critical point, equal pressure drops result in different volume percentages of the liquid phase in the two -phase region. The pressure drop represented by the blue bar further from the critical point results in a two-phase system with 90 percent of the volume occupied by the liquid phase; while the blue bar closer to the critical point results in a two-phase system with 80 percent of the volume occupied by the liquid phase. Thus, the volume of the liquid phase shrinks more in a system that is closer to the critical point for similar pressure drops. Since the liquid phase occupies less volume for a volatile, high shrinkage oil for comparable pressure drops, at abandonment the secondary gas cap will occupy a larger volume.

3. Saturated Black Oil (Low Shrinkage) Reservoirs

Figure 27 (B) shows a saturated black oil in an anticlinal trap. In this figure, we can see that a gas cap overlies the oil at discovery. Since this gas accumulation was present at the original temperature and pressure conditions, we refer to this gas accumulation as a “primary gas cap.” Figure 27 (C) shows the state of the reservoir at abandonment conditions. As shown in this figure, at the lower pressure condition, the gas cap size has expanded.

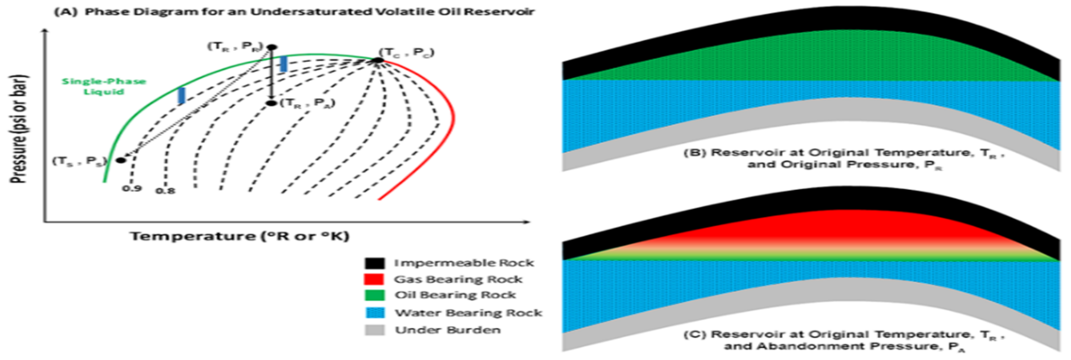


Figure 27 Saturated Black Oil (Low Shrinkage) Reservoirs

The definition of a “volatile fluid” is a fluid that easily evaporates or vaporizes. This definition gives rise to the name “volatile oils.” These systems develop larger gas phase volumes for comparable pressure drops when entering the two-phase region of the phase envelope.

4. Undersaturated Black Oil (Low Shrinkage Oil) Reservoirs

Undersaturated black oils, sometimes referred to as “low shrinkage oils,” are single-phase liquid systems that reside in reservoirs with an original temperature that is significantly lower than critical temperature, TC.

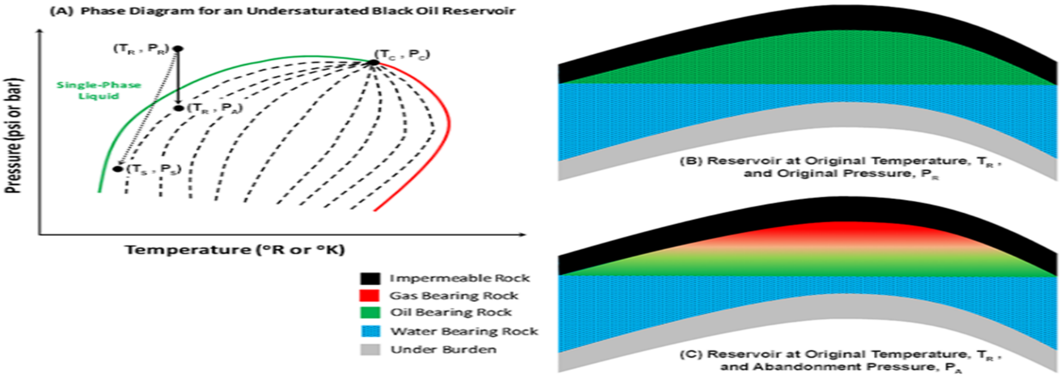


Figure 28 Undersaturated Black Oil (Low Shrinkage) Reservoirs

In this figure, the reservoir temperature, T_R, and reservoir pressure, P_R, at the time of discovery are determined by the earth's local temperature gradient and hydrostatic pressure gradient, respectively. The phase diagram for the crude oil is determined by the composition of the crude oil. As shown in this figure, the original reservoir temperature and pressure lie in the single-phase liquid region of the phase diagram at a temperature lower than the critical temperature.

The term "undersaturated" implies that the crude oil has the capacity to dissolve additional gaseous components and remain in the single-phase region. For example, if we change the composition of the system by adding lower molecular weight components (e.g., methane and ethane), then the phase envelope would expand with the bubble-point locus beginning to shift towards the Point (T_R, P_R). In this example, we could continue to add gaseous components to the system until the bubble-point locus has shifted all of the way to the Point (T_R, P_R). At this point, with Point (T_R, P_R) lying on the bubble-point locus, we would call the fluid a bubble-point fluid. This is the point where the system would be unable to accept additional gaseous components and still remain a single-phase liquid, i.e., a single-phase crude oil.

The production of oil and gas is an isothermal process. We typically deplete the reservoir pressure by removing fluids from the system. Even in the cases where we inject fluids at different temperatures into the reservoir, such as with steam injection, the volume of fluids that we inject are so small compared to the size of the reservoir and the over- and under-burdens that, at most, we cause a local change in the temperature at the point of injection and have no significant impact on the temperature of the system. For isothermal processes, the pressure-temperature path of the fluids inside the reservoir is a vertical line at a fixed temperature. This is represented in Figure 28 (A) as the solid black arrow going from Point (T_R, P_R) to Point (T_R, P_A).

5. Wet Gas Reservoirs

Wet gas reservoirs are gaseous hydrocarbon systems that reside in reservoirs with the original temperatures above the cricondentherm. In addition, the field surface facilities, separators, gas plant, etc., are in the two-phase region of the system's phase diagram. This is shown in Figure 29. Under these conditions, as the pressure in the reservoir is reduced due to production, the reservoir never enters the two-phase region of the gas and no hydrocarbon liquids drop out in the reservoir. That is, as pressure is reduced, the hydrocarbon fluid in the reservoir remains in its gaseous state. However, as the produced gas travels up the well and to the surface, at some point in the production system it enters the two-phase region of the phase envelope and liquid hydrocarbons develop in the well or surface facilities.

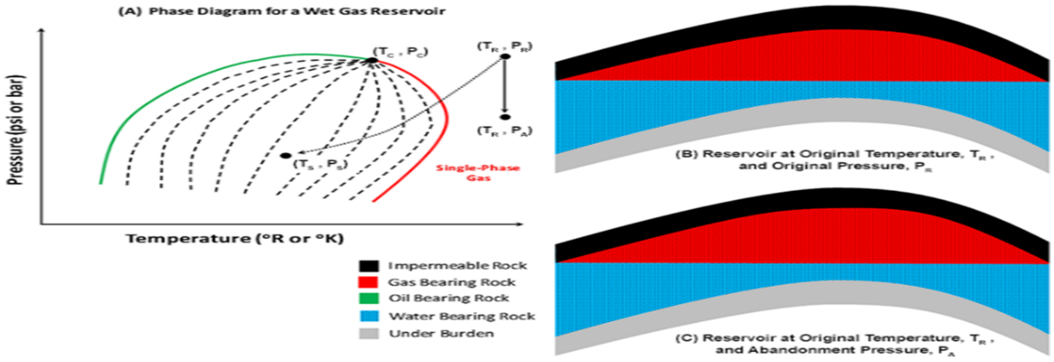
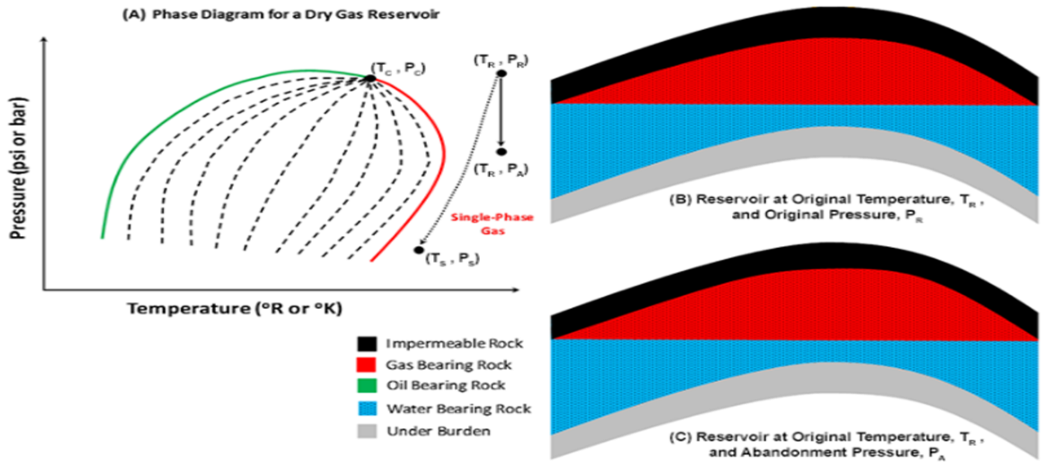


Figure 29 Wet gas reservoirs

6. Dry Gas Reservoirs

Dry gas reservoirs are gaseous hydrocarbon systems that reside in reservoirs with the original temperatures above the cricondentherm. In addition, the surface conditions are also greater than the cricondentherm. This is shown in Figure 2.18. Under these conditions, as the pressure in the reservoir is reduced due to production, both the fluids in the reservoir and the fluids in the production system remain a single gaseous phase.



B. Classification of Reservoirs on the Basis of Storage and Flow Characteristics of Reservoirs.

In accordance with different **storage spaces** and **main flow channels** of formation fluids, oil and gas reservoirs can be divided into the following types, shown in the table below:

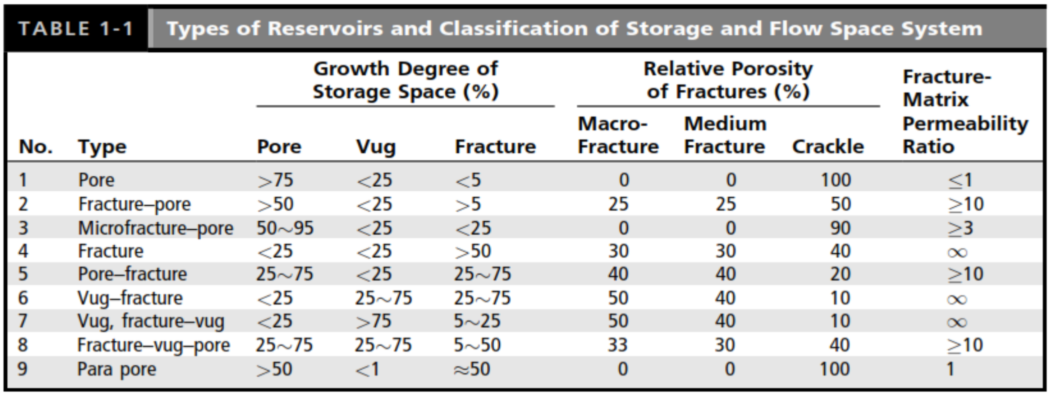


TABLE 1-1 Types of Reservoirs and Classification of Storage and Flow Space System

		Growth Degree of Storage Space (%)			Relative Porosity of Fractures (%)			Fracture-Matrix Permeability Ratio
No.	**Type**	**Pore**	**Vug**	**Fracture**	**Macro-Fracture**	**Medium Fracture**	**Crackle**	
1	Pore	>75	<25	<5	0	0	100	≤1
2	Fracture–pore	>50	<25	>5	25	25	50	≥10
3	Microfracture–pore	50~95	<25	<25	0	0	90	≥3
4	Fracture	<25	<25	>50	30	30	40	∞
5	Pore–fracture	25~75	<25	25~75	40	40	20	≥10
6	Vug–fracture	<25	25~75	25~75	50	40	10	∞
7	Vug, fracture–vug	<25	>75	5~25	50	40	10	∞
8	Fracture–vug–pore	25~75	25~75	5~50	33	30	40	≥10
9	Para pore	>50	<1	≈50	0	0	100	1

1. **Porous reservoir. The storage space and percolation channels are the inter-granular pores.** Therefore, the flow is called **flow in porous media** such as **sandstone,** conglomerate, bioclastic limestone, and oolitic limestone reservoirs.

2. **Fractured reservoir**. **Natural fractures are not only the main storage space, but also the flow channels.** There may be no primary pores or be disconnected pores. Generally, the fracture porosity is not more than 6%. Tight carbonatite and metamorphic rock reservoirs, and mud shale gas reservoirs, are of this type of reservoir.

3. **Fracture porosity reservoir**. **Inter-granular pores are the main storage space, whereas fractures are the main flow channels.** The flow is called **flow in dual-porosity single-permeability media.** Usually, the fractures extend for a long distance, But the pore permeability is very low. The **Renqiu carbonatite oil field of China** and the **Spraberry Trend oil field of the United States** are of this type of reservoir.

4. **Porous fractured reservoir**. Both intergranular pores and fractures are the storage space and the flow channels. The flow is called flow in **dual-porosity dual-permeability media**. Fractures grow fine, but extend for a short distance. The matrix porosity is low.

5. **Combined fracture–vug–pore reservoir.** Fractures, vugs, and pores are both the storage space and the flow channels. All reservoirs of this type are **soluble salinastone**. The secondary pores are the main. This type of reservoir is also called a triple-porosity reservoir.

C. Classification of Reservoirs on the Basis of Reservoir Geometry.

In accordance with the geometry, reservoirs can be divided into:

- massive,
- stratified,
- fault block, an
- lenticular reservoirs.

1. **Massive reservoir**

The reservoir has a large effective thickness (more than 10m). The oil reservoir may have a gas cap and bottom water while the gas reservoir may have bottom water. The reservoir has a unitized hydrodynamic system and good connectivity. The bottom water has rechargeablity. When choosing completion modes, whether gas cap and bottom water exist for oil reservoir and whether bottom water is active for gas reservoir should be considered. Generally, perforating or open hole completion is selected.

2. Stratified reservoir

Most reservoirs of this type belong to an **anticlinal trap with a complete structure and a unitized oil–water interface.** It has good stratification and a number of beds along a vertical section. Every individual bed has a small thickness. A bed with a thickness of 5–10, 1–5, and less than 1m is called thick, medium thick, and thin, respectively. These beds differ greatly in permeability. The drive energy of edge water is weaker. Separate zone water injection, separate zone fracturing, and separate zone water shutoff should be applied during water flooding in order to control injection and production profiles and increase flooding efficiency, thus the perforated completion mode is generally adopted. Reservoirs in the Daqing Shaertu, Shengli Shengtuo, and Changqing Malin oil fields in China are of this type of reservoir.

3. Fault block reservoir

Fractures are well developed in reservoirs of this type. The structure is cut into many fault blocks of different sizes. The areas of some fault blocks are less than 0.5 km2. Vertically, there are many oil-bearing series of strata with a long total oil-bearing section. In each fault block or even various reservoir groups in the same fault block, different oil–water interfaces and obvious differences in degrees of oil and gas enrichment, physical property of reservoir, and natural drive energy exist. For a seal-type fault block, elastic energy is used in the early stage, whereas selective scattered flooding is used in the late stage. Peripheral or outer edge water-flooding is applicable to the open-type fault block. Generally, the perforated completion mode is adopted for this type of reservoir due to their numerous oil-bearing series of strata and the great interlayer differences. The Shengli Dongxin and Zhongyuan Wenminzhai oil fields are of this type of reservoir.

4. Lenticular reservoir

The geologic description of geometry for a sand body depends on the length-to-width ratio. A sand body with a ratio less than or equal to 1 is called lens. Lenses are scattered, and the major area is occupied by the pinch out region. When lenses alternately overlap each other, multiple reservoirs may appear on the vertical oil and gas-bearing well section.

C. Classification of Reservoirs on the Basis of Main Characteristics of Development Geology. The continental reservoirs in China are divided into multilayer sandstone oil reservoirs, gas cap sandstone oil reservoir, low-permeability sandstone oil reservoirs, complex fault-block sandstone oil reservoirs, glutenite oil reservoirs, fractured buried-hill basement rock reservoirs, conventional heavy oil reservoirs, high pour-point oil reservoirs, and condensate gas reservoirs in accordance with the main characteristics of development geology and the development mode of the continental reservoirs in

China.

Life Cycle of a Reservoir

The life cycle of a reservoir begins when the field becomes an exploration prospect and does not end until the field is properly abandoned. An exploration prospect is a geological structure that may contain hydrocarbons. The exploration stage of the project begins when resources are allocated to identify and assess a prospect for possible development. This stage may require the acquisition and analysis of more data before an exploration well is drilled. Exploratory wells are also referred to as wildcats. They can be used to test a trap that has never produced, test a new reservoir in a known field, and extend the known limits of a producing reservoir. Discovery occurs when an exploration well is drilled and hydrocarbons are encountered.

The figure below illustrates a typical production profile for an oil field beginning with the discovery well and proceeding to abandonment. Production can begin immediately after the discovery well is drilled or several years later after appraisal and delineation wells have been drilled. Appraisal wells are used to provide more information about reservoir properties and fluid flow. Delineation wells better define reservoir boundaries. In some cases, delineation wells are converted to development wells. Development wells are drilled in the known extent of the field and are used to optimize resource recovery. A buildup period ensues after first oil until a production plateau is reached. The production plateau is usually a consequence of facility limitations such as pipeline capacity. A production decline will eventually occur. Production continues until an economic limit is reached and the field is abandoned.

Production profile of an oil field

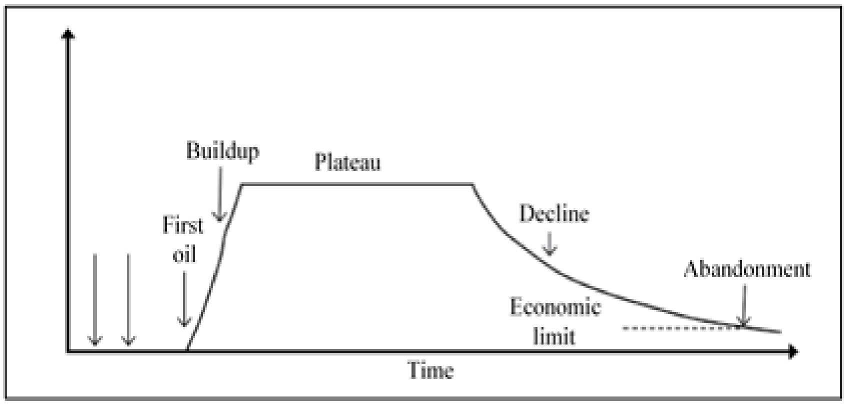


Figure 2. Life cycle of a reservoir

Petroleum engineers provide input to decision makers in management to help determine suitable optimization criteria. Fields produced over a period of years or decades may be operated using optimization criteria that change during the life of the reservoir. Changes in optimization criteria occur for a variety of reason, including changes in technology, changes in economic factors, and the analysis of new information obtained during earlier stages of production.

Traditionally, production stages are identified by chronological order as:

A. Primary,
B. secondary, and
C. tertiary production.

Primary production is the first stage of production and relies entirely on natural energy sources to drive reservoir fluids to the production well. The reduction of pressure during primary production is often referred to as primary depletion. Oil recovery can be increased in many cases by slowing the decline in pressure. This can be achieved by supplementing natural reservoir energy. The supplemental energy is provided using an external energy source, such as water injection or gas injection. The injection of water or natural gas may be referred to as pressure maintenance or secondary production. Pressure maintenance is often introduced early in the production life of some modern reservoirs. In this case the reservoir is not subjected to a conventional primary production phase.

Historically, primary production was followed by secondary production and then tertiary production (Figure below). Notice that the production plateau shown in the figure does not have to appear if all of the production can be handled by surface facilities.

Secondary production occurs after primary production and includes the injection of a fluid such as water or gas. The injection of water is referred to as water flooding while the, injection of a gas is called gas flooding. Typical injected gases include methane (methane), carbon dioxide (CO_2), or nitrogen. Gas flooding is considered a secondary production process if the gas is injected at a pressure that is too low to allow the injected gas to be miscible with the oil phase. A miscible process occurs when the gas injection pressure is high enough that the interface between gas and oil phases disappears.

In the miscible case, injected gas mixes with oil and the process is considered an enhanced oil recovery (EOR) process.

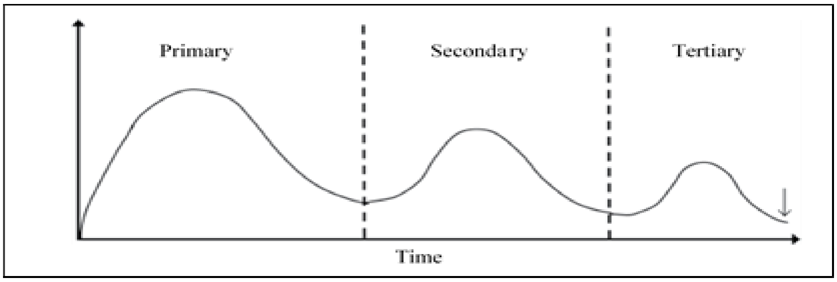


Figure 3.

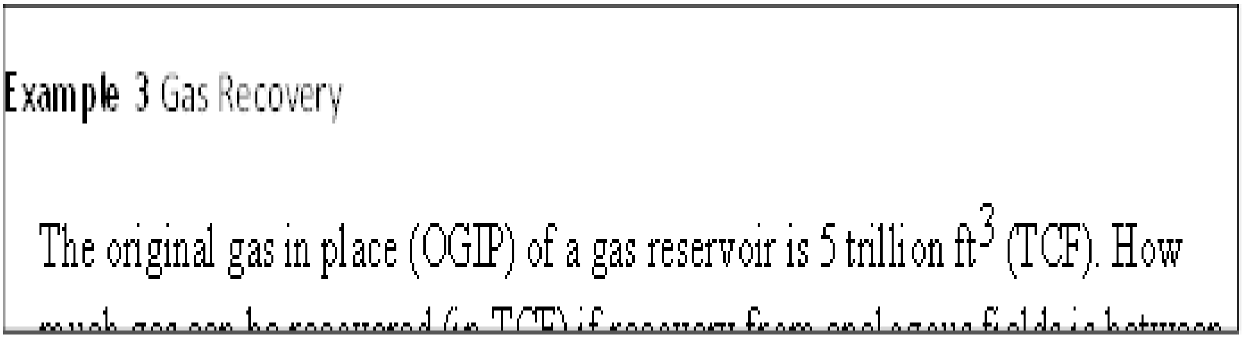
EOR processes include

1. Miscible,
2. Chemical,
3. Thermal, and
4. Microbial processes.

- **Miscible processes** inject gases that can mix with oil at sufficiently high pressures and **temperatures.**
- **Chemical processes** use the injection of chemicals such as polymers and surfactants to **increase oil recovery.**
- **Thermal processes add heat to the reservoir.** This is achieved by injecting heated fluids such as steam or hot water or by the injection of oxygen-containing air into the reservoir and then burning the oil as a combustion process. The additional heat reduces the viscosity of the oil and increases the mobility of the oil.
- **Microbial processes** use microbe injection to reduce the size of high molecular weight hydrocarbons and improve oil mobility. EOR processes were originally implemented as a third, or tertiary, production stage that followed secondary production.

EOR processes are designed to improve '**displacement efficiency'** by injecting fluids or heat. The analysis of results from laboratory experiments and field applications showed that some fields would perform better if the EOR process was implemented before the third stage in field life. In addition, it was found that EOR processes were often more expensive than just drilling more wells in a denser pattern. The process of increasing the density of wells in an area is known as infill drilling. The term improved oil recovery (IOR) includes EOR and infill drilling for improving the recovery of oil. The addition of wells to a field during infill drilling can also increase the rate of withdrawal of hydrocarbons in a process known as acceleration of production.

Several mechanisms can occur during the production process. For example, production mechanisms that occur during primary production depend on such factors as reservoir structure, pressure, temperature, and fluid type. Production of fluids without injecting other fluids will cause a reduction of reservoir pressure. The reduction in pressure can result in expansion of in situ fluids. In some cases, the reduction in pressure is ameliorated if water moves in to replace the produced hydrocarbons. Many reservoirs are in contact with water-bearing formations called aquifers. If the aquifer is much larger than the reservoir and is able to flow into the reservoir with relative ease, the reduction in pressure in the reservoir due to hydrocarbon production will be much less that hydrocarbon production from a reservoir that is not receiving support from an aquifer.



Example 3 Gas Recovery

The original gas in place (OGIP) of a gas reservoir is 5 trillion ft^3 (TCF). How

Reservoir Management

One definition of reservoir management says that the primary objective of reservoir management is to determine the optimum operating conditions needed to maximize the economic recovery of a subsurface resource. This is achieved by using available resources to accomplish two competing objectives: optimizing recovery from a reservoir while simultaneously minimizing capital investments and operating expenses. As an example, consider the development of an oil reservoir. It is possible to maximize recovery from the reservoir by drilling a large number of wells, but the cost would be excessive. On the other hand, drilling a single well would provide some of the oil but would make it very difficult to recover a significant fraction of the oil in a reasonable time frame.

Reservoir management is a process for balancing competing objectives to achieve the key objective.

An alternate definition says that reservoir management is a continuous process designed to optimize the interaction between data and decision making.

Both definitions describe a dynamic process that is intended to integrate information from multiple disciplines to optimize reservoir performance. The process should recognize uncertainty resulting from our inability to completely characterize the reservoir and fluid flow processes. The reservoir management definitions given earlier can be interpreted to cover the management of hydrocarbon reservoirs as well as other reservoir systems. For example, a geothermal reservoir is essentially operated by producing fluid from a geological formation. The management of the geothermal reservoir is a reservoir management task.

It may be necessary to modify a reservoir management plan based on new information obtained during the life of the reservoir. A plan should be flexible enough to accommodate changes in economic, technological, and environmental factors. Furthermore, the plan is expected to address all relevant operating issues, including governmental regulations. Reservoir management plans are developed using input from many disciplines.

Recovery Efficiency

An important objective of reservoir management is to optimize recovery from a resource. The amount of resource recovered relative to the amount of resource originally in place is defined by comparing initial and final in situ fluid volume.

The ratio of fluid volume remaining in the reservoir after production to the fluid volume originally in place is recovery efficiency. Recovery efficiency can be expressed as a fraction or a percentage. An estimate of recovery efficiency is obtained by considering the factors that contribute to the recovery of a subsurface fluid: displacement efficiency and volumetric sweep efficiency.

Displacement efficiency ED is a measure of the amount of fluid in the system that can be mobilized by a displacement process. For example, water can displace oil in a core. Displacement efficiency is the difference between oil volume at initial conditions and oil volume at final (abandonment) conditions divided by the oil volume at initial conditions:

$$E_D = \frac{(S_{oi}/B_{oi}) - (S_{oa}/B_{oa})}{S_{oi}/B_{oi}}$$

Where:

- S_{oi} is initial oil saturation
- S_{oa} is oil saturation at abandonment.

NOTE:

Oil saturation is the fraction of oil occupying the volume in a pore space.

Abandonment refers to the time when the process is completed.

Formation volume factor (FVF) is the volume occupied by a fluid at reservoir conditions divided by the volume occupied by the fluid at standard conditions. The terms B_{oi} and B_{oa} refer to FVF initially and at abandonment, respectively.

Exp. 4 Suppose oil occupies 1 bbl at stock tank (surface) conditions and 1.4 bbl at reservoir conditions. The oil volume at reservoir conditions is larger because gas is dissolved in the liquid oil. What is the FVF of the oil?

Solution: Oil FSF = vol. at reservoir conditions⁄vol. at surface conditions

Oil FVF = 1.4RB/1STB

Oil FVF = 1.4RB/STB

Volumetric sweep efficiency E_{vol} expresses the efficiency of fluid recovery from a reservoir volume. It can be written as the product of areal sweep efficiency and vertical sweep efficiency:

$E_{vol} = E_A \times E_V$

Areal sweep efficiency EA and vertical sweep efficiency EV represent the efficiencies associated with the displacement of one fluid by another in the areal plane and vertical dimension. They represent the contact between in situ and injected fluids.

Areal sweep efficiency is defined as **E = swept area/total area**

Vertical sweep efficiency is defined as **EV = swept net thickness/total net thickness**

Recovery efficiency RE, is the product of displacement efficiency and volumetric sweep efficiency:

$R_E = E_D \times E_V$

$= E_D \times E_V \times E_A$

EXP. 5 Calculate volumetric sweep efficiency E_{Vol} and recovery efficiency RE from the following data: $S_{oa} = 0.75$, $S_{oi} = 0.30$, area swept = 750 acres, total area = 1000 acres, thickness swept = 10 ft, total thickness = 15 ft. Neglect FVF since B_{oi} is equivalent to B_{oa}.

Soln.

Crude oils are also defined in terms of API (specific) gravity. For example, heavier crude oils have low API gravities (and high specific gravities). A low-API gravity crude oil may have either a high or low flashpoint, depending on its lightest ends (more volatile constituents).

Because of the importance of temperature and pressure in the refining process, crude oils are further classified as to viscosity, pour points and boiling ranges. Other physical and chemical characteristics, such as colour and carbon residue content, are also considered.

Crude oils with high carbon, low hydrogen and low API gravity are usually rich in aromatics; while those with low carbon, high hydrogen and high API gravity are usually rich in paraffins.

Crude oils which contain appreciable quantities of hydrogen sulphide or other reactive sulphur compounds are called “sour.” Those with less sulphur are called “sweet.” Some exceptions to this rule are West Texas crudes (which are always considered “sour” regardless of their H_2S content) and Arabian high-sulphur crudes (which are not considered “sour” because their sulphur compounds are not highly reactive.

Exploration and Production

The search for oil and gas requires a knowledge of geography, geology and geophysics. Crude oil is usually found in certain types of geological structures, such as **anticlines, fault traps and salt domes**, which lie under various terrains and in a wide range of climates. After selecting an area of interest, many different types of geophysical surveys are conducted and measurements performed in order to obtain a precise evaluation of the subsurface formations. The goal of exploration is to identify and locate a prospect, to quantify the volume of hydrocarbon which might be contained in the potential reservoirs and to evaluate the risk inherent in the project itself.

A prospect is a viable target evidenced by geological and geophysical indications that is recommended for drilling an exploration well, and the results obtained by drilling the exploratory wells will indicate whether the initial geological hypotheses are correct or whether variations are found.

Figure C

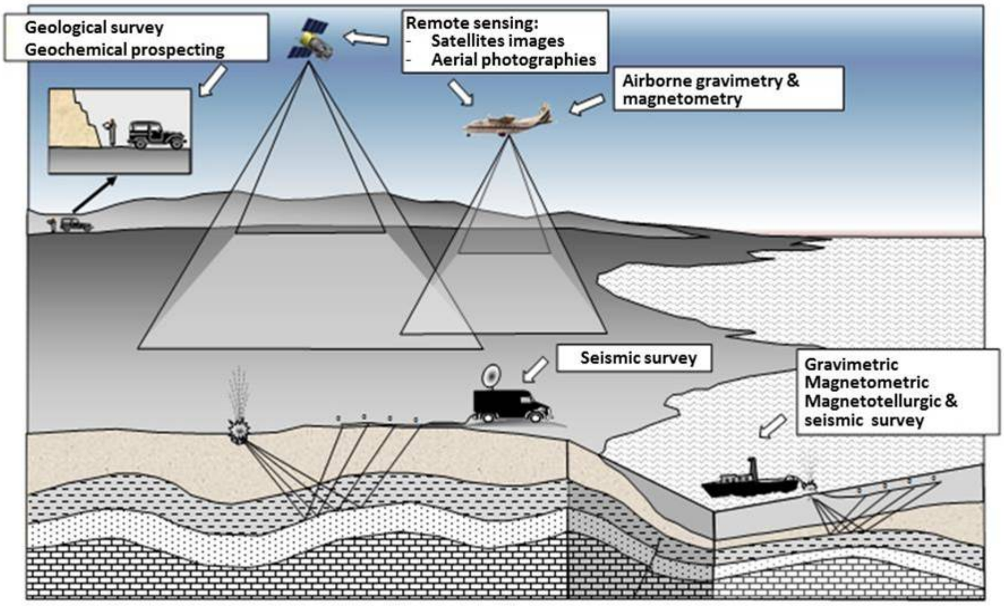


Figure C above outlines the main techniques used in oil prospecting.

Stages of a typical exploration program

Exploration is responsible for handling the risk intrinsic in this activity, and this is generally achieved by selection of a range of options in probabilistic and economic terms. Indeed, exploration is a risk activity and the management of exploration assets and associated operations is a major task for oil companies, and these risks cannot be eliminated entirely but can be controlled and reduced adopting appropriate workflow, conceptual and technological innovations.

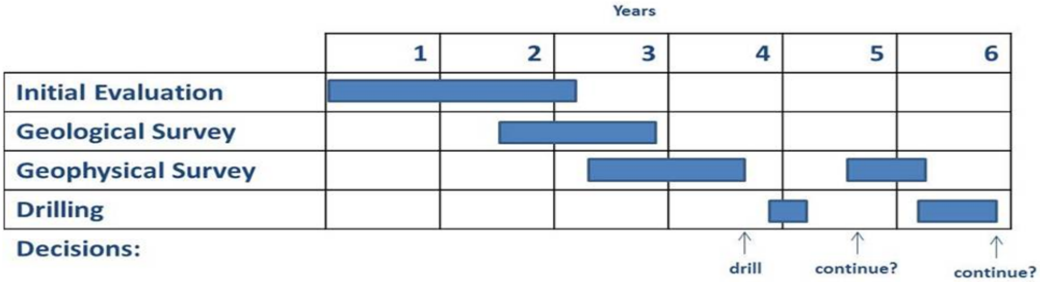


Figure D shows the stages in the exploration process of oil and gas

When it’s been decided to start up with an exploration project in a basin or in a larger area containing several basins, the quantity and quality of available data must be acquired and evaluated – geological data, type of reserves, production of existing fields (if any), etc.

Basin assessment/evaluation is the first step to undertake the study of the area under interest.

Technological development has provided oil prospectors with Basin Modeling – which is a **numerical simulation** that allows the temporal reconstruction of the history of a sedimentary basin and the associated evolution of the processes related to the formation of petroleum accumulations

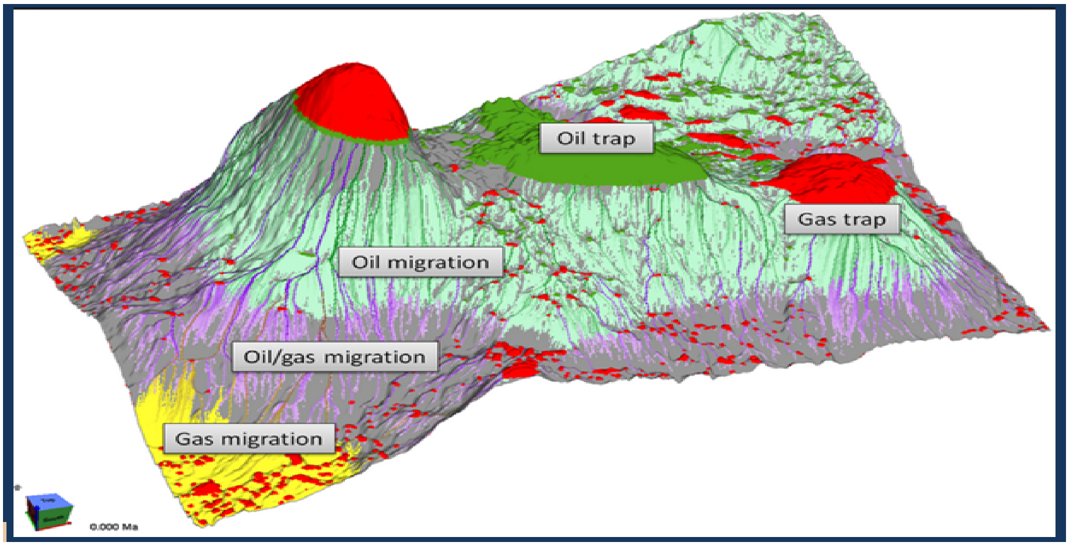


Figure E. Shows Basin modeling – Petroleum system

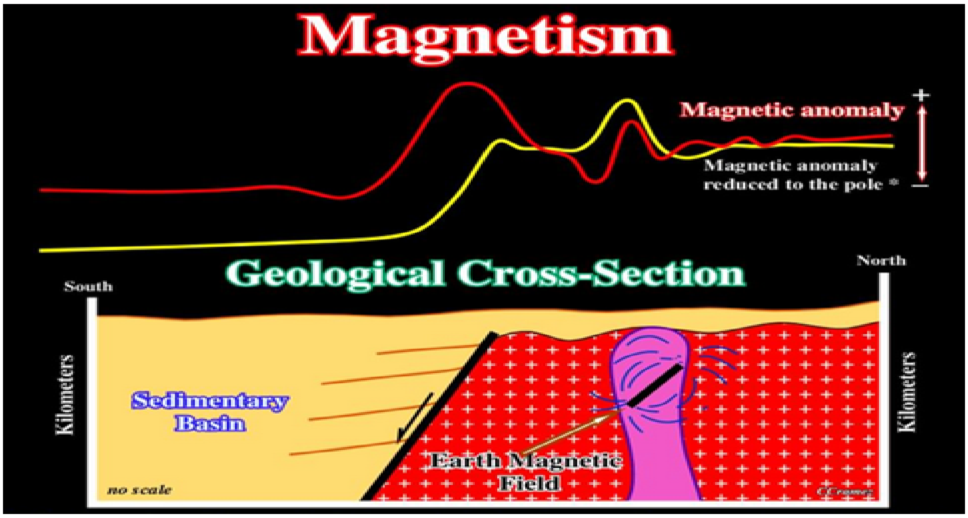
On the basis of data and evidences collected from the preliminary studies, the exploration team or company or management, in the light of the possibilities and the probabilities of a discovery based on 'geological and geophysical' data, aside from considerations of an economic nature, may decide to move to the following stage, which is the acquisition of the legal right to drill. Since the geological and geophysical information have defined and evaluated (technically and economically) the drillable prospect, it is possible to move to a fundamental phase of the exploration project – the drilling of the first exploratory well.

The drilling of the exploration well is aimed to confirm the presence of the petroleum accumulation.

Basically, the different methods used in prospecting of oil and gas are:

A. Magnetometric Surveys

In this type of survey, magnetometers are used to measure variations in the earth's magnetic field in order to locate sedimentary rock formations which generally have low magnetic properties when compared to other rocks.

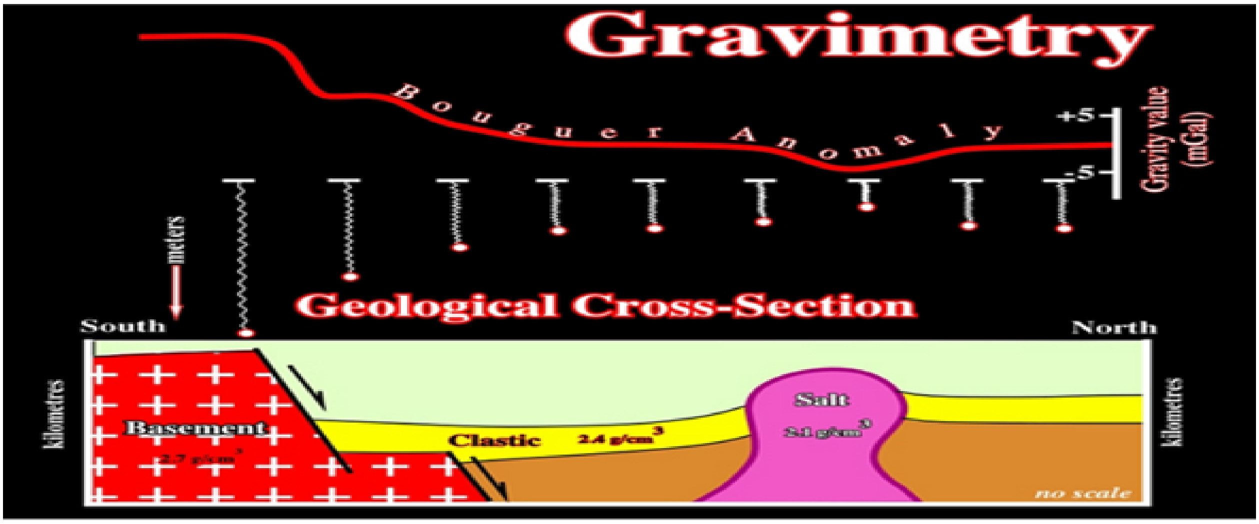


This method involves measuring local anomalies in the Earth’s magnetic fields. The method enables the acquisition of data on structural characteristics and depth of the susceptive basement and therefore, indirectly, on the thickness of sedimentary overburden and identifies the presence, depth and extension of volcanic or plutonic masses within the sedimentary sequences.

B. Gravimetric Prospecting

Geophysical Gravimetry, as a branch of applied geophysics, is concerned with the investigation of the interior of the earth. Its’ methodology involves taking measurements that are influenced by the distribution of the earth's crustal masses. Modelling and analysis of these measurements reveals the physico-chemical properties of these masses in the form of the size, shape, structure and dynamics so that mineral deposits and other subsurface features can be identified. The gravimetric method has been found a very useful tool for the determination of mass anomalies within the crust. Inverse gravimetric techniques compute sizes, shapes and component characteristics of the observed mass anomalies. In this way, the method has been extensively used for the exploration, exploitation and development of underground mineral resources including aquifers, oil, gas and other minerals. The search for oil and gas requires principally a knowledge of gravity data among other geophysical information. Crude oil is usually found in certain types of geological structures, such as anticlines, fault traps and salt domes, which lie under various terrains and in a wide range of climates. After selecting an area of interest, many different types of geophysical surveys are conducted and measurements performed in order to obtain a precise evaluation of the subsurface formations. Gravimetric surveys provide information regarding underlying formations by measuring minute differences in gravity. The exploitation and extraction of such minerals in the form of the liquid and gas components of the upper crust especially in readily deformable sedimentary planes reduces the load bearing capacity of such strata. The overlying burden responds by deforming in shape. Gravity measurements at different epochs are capable of revealing the dynamics of such crustal movement. The method describes the subsoil in terms of density, depth and geometry of rocks by studying gravimetric anomalies which are calculated, isolating from the measured value at a certain location, the calculated theoretical effect based on a mathematical simulation of gravity for the same location.

Gravimetry is characterized by its efficiency, profitability, and versatility, as it requires little staff to acquire data, and can be carried out as: ground acquisition, marine and airborne.



3. Aerial photogrammetric surveys.

Photographs taken with special cameras in airplanes, provide three-dimensional views of the earth which are used to determine land formations with potential oil and gas deposits. A shift in topography, contours, rock type formation and other useful data are analyzed to give the probable presence of crude oil in the underlying geologic rocks.

4. Seismic surveys.

Seismic studies provide information on the general characteristics of the subsurface structure. Measurements are obtained from shock waves generated by setting off explosive charges in small-diameter holes, from the use of vibrating or percussion devices on both land and in water, and from underwater blasts of compressed air. The elapsed time between the beginning of the shock wave and the return of the echo is used to determine the depth of the reflecting substrata. The recent us of super-computers to generate three-dimensional images greatly improves evaluation of seismic test results. Seismic prospecting has become the most valuable technique to reduce exploration risk of being unsuccessful in locating a prospect. Basically, the technique is based on determinations of the time interval that elapses between the initiation of a seismic wave at a selected shop point and the arrival of reflected or refracted impulses at one or more seismic detectors.

The phase of seismic data acquisition is followed by the seismic data processing phase (aimed to the alteration of seismic data to suppress noise, enhance signal and migrate seismic events to the appropriate location in space) than by the interpretation of the generated subsurface image.

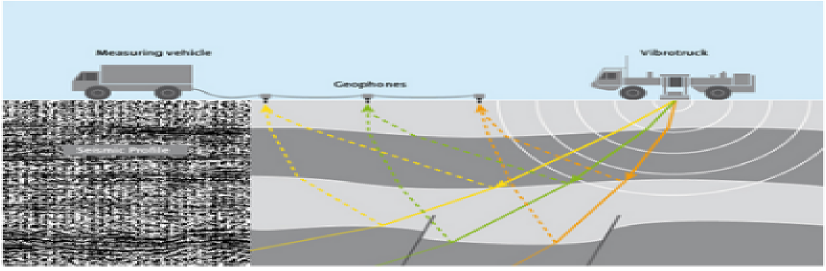
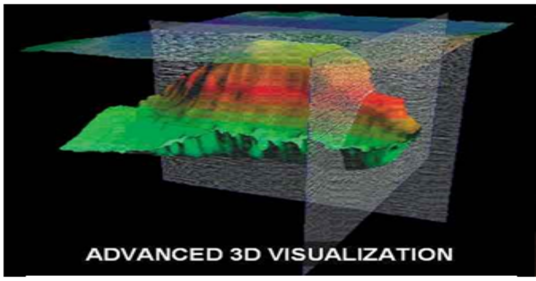


Figure d. Onshore seismic survey

Figure e. Marine seismic survey

Powered by advanced supercomputer power, rapid data loading, high-speed networking and high-resolution graphics, visualization centers provide the ability to display and manipulate complex volumes of 3D data resulting in better interpretation of more data in less time.



3D Seismic Visualization - GEOMORE

A visualization room

5. Radiographic Surveys

Radiography is the use of radio waves to provide information similar to that obtained from seismic surveys.

6. Stratigraphic Surveys

Stratigraphic sampling is the analysis of cores of subsurface rock strata for traces of gas and oil. A cylindrical length of rock, called a core, is cut by a hollow bit and pushed up into a tube (core barrel) attached to the bit. The core barrel is brought to the surface and the core is removed for analysis. When the surveys and measurements indicate the presence of formations or strata which may contain petroleum, exploratory wells are drilled to determine whether or not oil or gas is actually present and, if so, whether it is available and obtainable in commercially viable quantities.

Drilling

Extraction of oil and gas from a subsurface (e.g. reservoir) formation requires access to the resource. Drilling is one step in that direction. But before drilling, an operator must have the right to place equipment on the surface of the drilling site. Everywhere around the world, mineral rights give access to subsurface minerals and fluids and allow reasonable operations at the surface for extraction. The drilling process leads to the formation of wells, some of which are as below:

Exploratory wells.

Following the analysis of geological data and geophysical surveys, exploratory wells are drilled either on land or offshore. Exploratory wells which are drilled in areas where neither oil nor gas has been previously found are called **“wildcats**. Those exploratory wells which strike oil or gas are called “**discovery wells.”** Other exploratory wells, known as **“step-out” or “appraisal**” **wells** are drilled to determine the limits of a field following discovery, or to search for new oil- and gas-bearing formations next to, or beneath, those already known to contain product. A well which does not find any oil or gas, or finds too little to produce economically, is called a “**dry hole”.**

Developmental wells.

After a discovery, the area of the reservoir is roughly determined with a series of step-out or appraisal wells. Developmental wells are then drilled to produce gas and oil. The number of developmental wells to be drilled is determined by the expected definition of the new field, both in size and in productivity. Because of the uncertainty as to how reservoirs are shaped or confined, some developmental wells may turn out to be dry holes.

Geo-pressure/geothermal wells.

Geopressure/geothermal wells are those which produce extremely high-pressure (7,000 psi) and high-temperature (149 °C) water which may contain hydrocarbons. The water becomes a rapidly expanding cloud of hot steam and vapours upon release to the atmosphere from a leak or rupture.

Stripper wells.

Stripper wells are those which produce less than ten barrels of oil a day from a reservoir.

Multiple completion wells.

When multiple producing formations are discovered when drilling a single well, a separate string of pipe may be run into a single well for each individual formation. Oil and gas from each formation is directed into its respective piping and isolated from one another by packers, which seal the annular spaces between the piping string and the casing. These wells are known as multiple completion wells.

Injection wells.

Injection wells pump air, water, gas or chemicals into reservoirs of producing fields, either to maintain pressure or move oil toward producing wells by hydraulic force or increased pressure.

Service wells.

Service wells include those used for fishing and wire-line operations, packer/plug placement or removal and reworking. Service wells are also drilled for underground disposal of salt water, which is separated from crude oil and gas.

THE DRILLING PROCESS

The process of drilling begins months, and often years, before a drilling rig arrives on location. Here, the following five stages of the process will be considered:

- Planning,
- Site preparation,
- Drilling,
- Open-hole logging, and
- Setting production casing.

Planning is the longest of these five stages, and open-hole logging and setting of casing are the shortest, often just 1–3 days for each.

Planning

Planning begins with identification of target formations and their depths. The data used to identify the target could include data from offset (nearby) wells, seismic data, and other geologic insight. The data from offset wells includes all the drilling, logging, completion, and production records.

Well design starts after the target is selected. For some targets, a vertical well is the correct choice; but for others, a directional well may be needed. That choice depends on surface topography, surface buildings, lakes, and the subsurface formations that will be penetrated. The design will include drilling and casing operations. An authorization for expenditure (AFE) is prepared after a detailed drilling plan is complete. In general, the depth and complexity of the well will have the greatest impact on total cost. Complexity refers to variations in formation properties for each formation that is encountered during the drilling of the well. Completion costs usually dominate the cost of drilling shallow wells. Completion and drilling costs are often comparable for medium-depth wells. The cost of drilling deep wells is usually dominated by drilling costs. The AFE will include tangible and intangible costs, dry hole costs, completed well costs, overhead charges, and contingencies.

With the AFE completed, the production company must obtain stakeholder support from anyone involved with the well. Stakeholders include asset team members, different levels of management within the company, other partners, royalty owners, surface rights owners, regulators, public interest groups, and anyone that has a say on what happens to the well. Different stakeholders have different concerns or interests in the project that must be addressed.

Site Preparation: Land

The site preparations vary greatly depending on whether the oil and gas well to be dug is/are offshore on onshore. For onshore drilling, the next step after obtaining all permissions is to prepare a site for the drilling operation. Summarily, the process involves:

- Leveling the land on which the derrick will be assembled.
- Building access roads so workers and equipment can get to/from the rig.
- Reserve pits need to be dug so cuttings, material and used mud can be properly disposed of. In some locations, environmental laws prohibit drillers from digging mud pits. Instead, large metal bins are used at the rig site to catch all cuttings and waste materials which are then hauled offsite for disposal.
- The final step in site preparation is to dig what is called a cellar for equipment that will be needed during the well drilling operations. The cellar can be dug and formed in place with concrete, or it can be a pre-fabricated, four-walled steel structure that is driven into the ground to the desired depth. The cellar is set at the exact place where the well will be centered.

Offshore Drilling Preparation

Offshore drilling refers to the act of extracting underground resources which lie underwater off the coasts. The term can also apply to drilling in lakes, inland seas, bays or channels.

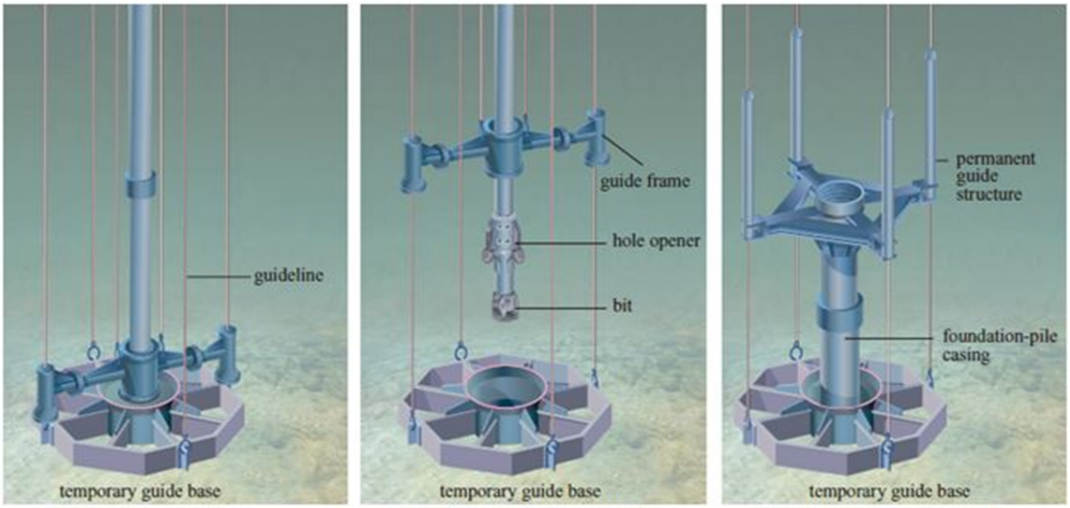
The actual process of drilling the well is similar to a land-based well, but the offshore location makes it more complex. Often, new wells are drilled while others are being produced from the same offshore production platform.

An offshore rig/platform is a small society or city with many support functions, including: cafeteria, sleeping quarters, entertainment halls and management teams. All rig personnel are transported in by helicopter or crew boats. Most staff are required to be onsite for rotating two-week shifts. Shift rotation can vary depending on location (especially, foreign) the E&P operator, drilling contractor and OFS service provider. All equipment, supplies and waste must be constantly transported in and out by work boat. Movements need to be delicately choreographed because of the limited floor space on the drilling rig/platform.

Drilling the Well (Spudding In)

The start of drilling is very commonly referred to as “spudding in.”

Once the cellar – a temporary **GUIDE BASE** which is a strong steel framework with a central hole having a tapered inlet at the top, provided with four guidelines and a number of steel pins that become embedded in the seabed and prevent displacement, placed on the seabed by means of a pipe string) is set. The pipe string is then disconnected, leaving only the temporary guide base on the seabed, with the four guidelines that connect up with the rig. Now the drilling phase can begin, so as to place the first casing (conductor pipe) and it is carried out using the circulation of seawater, the cuttings do not rise to the surface but are scattered over the seabed. The foundation pile (conductor pipe) is taken down to a depth of a few tens of meters. At this point the foundation pile is lowered into the hole again using a light frame and the four guidelines. It ends with a permanent guide structure, characterized by four tubular columns placed at the apexes, through which run the guidelines.



Temporary guide base   *Guide frame for the drill string*   *Foundation-pile casing and permanent guide structure*

Figure 5 shows various guide structures on the sea floor

The four columns serve in the subsequent phases to guide the submarine BOPs to the wellhead with precision.

The permanent guide structure contains the housing for the wellhead, to which the successive casings will be anchored.

The subsea wellhead has a different system of flanging and anchoring the casings and it is shaped in such a way as to enable the lock-up of the hydraulic connector to which the BOPs are coupled.

When the required depth is reached, the surface casing is lowered into place (through a riser), and cemented by pumping cement down the casing and up the annulus between the casing and the surrounding formations to the surface. The last step in cementing is to push a cement plug with drilling fluid down the casing until it reaches the bottom of the casing. Conductor pipe diameter ranges from 18 in. to more than 36 inch; its length is 40–80 ft. Two other smaller holes, the rat-hole and the mouse-hole, are often drilled within 10 ft. of the conductor hole. These holes are for temporary storage of pipe during the drilling process. Once the conductor pipe has also been fully cemented, the well has a stable structure and it is possible to install the submarine BOPs. BOP is used to shut the well in emergencies The foundation pile is fully cemented by means of a drill string.

Once the cement has set, drilling continues, boring the second section of the hole inside the foundation pile, in which the second casing is inserted.to install the submarine BOPs.

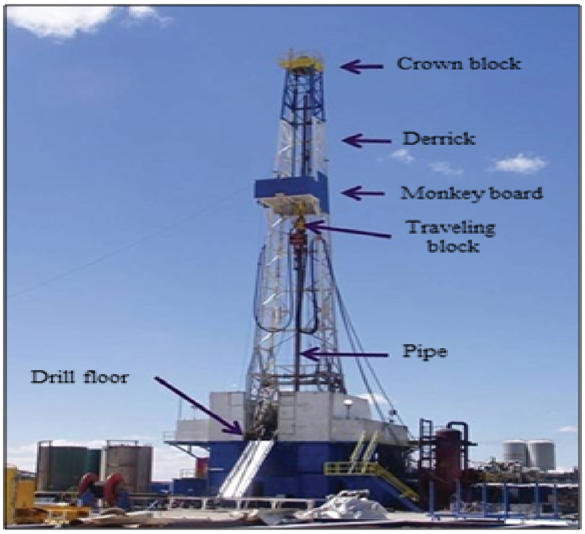


Figure 6 A typical rotary drilling rig

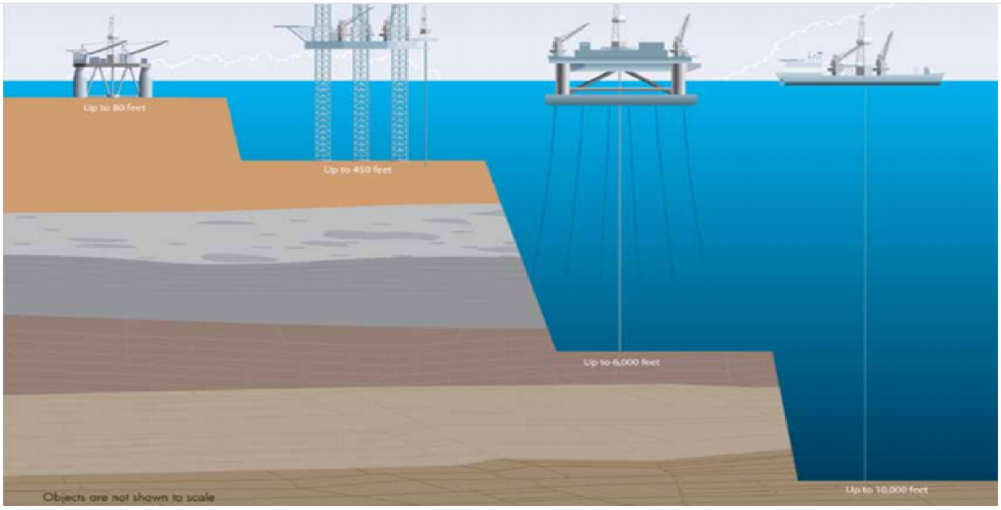


Figure 10 different offshore drilling rig.

Note: the offshore drilling rig to be used will largely depend on the water depth and remoteness of the reservoir.

The surface casing has two functions: first, it protects water in aquifers near the surface from contamination; second, it provides mechanical support for the well. The drilling fluid for the surface hole is typically freshwater.

For many wells, the next drilling objective is the depth of the target formation. While drilling to this

depth, the crew will adjust the composition of the mud as needed to clean the hole and maintain pressure control.

The next step in the well drilling plan is to lower a drill bit down inside the 36" casing set into the seafloor. Once the drill bit enters inside the 36" casing a drill of 2000-3000' is made into the ground. Care has to be taken to ensure that the bit used is large enough so that the next section of the casing can be run into the ground (running the casing inside the 36" casing). Mud is continuously run into the drill pipes, into the nozzle of the bits in order to: cool the drill bits, lubricate the process, maintain pressure, prevent the well from caving in or “taking a kick,” and carry drill cuttings with the to the top sides for processing. After the desired depth of drilling is reached, the drill bits and the drill pipes are brought to the surface, and then begin lowering the 22" casing back down to the sea floor – through the BOP – into the dug freshly dug hole. Once the 22" casing is set inside the 36" casing, the two different sized casings are cemented in place by passing cement – the drilled pipe (out through a special nozzle on the end of the pipe), into the casing which goes down to the end of the drilled hole. As usual, the cement goes up the annulus between the casing and the surrounding formations to the surface This is a very critical step in the operation. The cement must be mixed very carefully, and every effort should be made to ensure the nozzle is lowered to the correct position inside the casing. Once the cement has been pumped down the drill pipe and back up around the sides of the casing (filling in the space between the casing and the drilled hole, it takes anywhere from 4-12 hours for to harden.

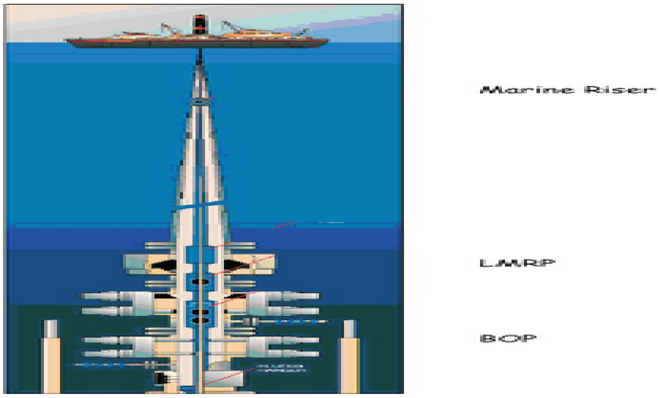


Figure 10. A subsea BOP stack

Open-Hole Logging

The processes continue until the hydrocarbon reservoir or target depth is reached and decisions made whether to set production casing and complete the well, or plug and abandon the well. The decisions will be informed by the data collected through the logging of the well with tools deployed on a wireline composed of steel cable wrapped multiple strands of electrically conductive wire. Logging at this stage of the drilling process is open-hole logging because there is no casing in the hole.

When properly interpreted, open-hole logs show lithology, porosity, and water saturation in the rock around the hole from bottom to top of the logged interval. The log also includes the diameter of hole measured by the caliper from bottom to top. Hole diameter is important for two reasons. First, interpretability of the other logs rapidly declines if the hole diameter is not constant. And second, the diameter is used to estimate the amount of cement needed to case or plug the well.

While there is a wide assortment of tools available, the most commonly used are the gamma-ray tool, formation density tool, neutron density tool, and a caliper. When these tools are assembled, the total length of the logging string can be 80–120 ft. The lubricator is a pipe of sufficient length and diameter to hold the assembled logging string. The lubricator is assembled with the cable running through the stuffing box at its top and then through to its open bottom, attaching the cable to the top of the logging string, pulls the logging string into the lubricator, using a drill rig hoist to raise the lubricator to flange to the top of the BOP.

With the lubricator attached to the top of the BOP, the logging tools are carefully lowered to the bottom of the well, using the weight indicator for signs of tool sticking. The length of hanging cable is also measured as it unwinds from the drum of the wireline truck. One of the first major measurements made with the wireline string is total depth of the well. This depth is compared to the depth recorded by the driller based on length of the drill string. With total depth verified and any differences resolved, the logging tools are slowly raised and records all of the data received from the tools are recorded. Data is not collected on the downward trip but on the upward trip because the upward trip gives more reliable depth measurements. The time needed for logging varies from about 6 to 24 hr, depending on the depth range that is logged and the allowed rising speed of the logging tools. During this time, the drilling crew must be alert for signs of kicks that can occur while logging, especially on the upward stroke.

In addition to open-hole logging, operators may use other tests to assess the exposed formations. Using the drill string, the drill stem test (DST) can measure the productive capacity of formations. Using wireline, the repeat formation tester (RFT) can measure pressure in formations and collect small volumes of formation fluids. Both of these tests can end with a tool stuck in the hole. Indeed, the RFT is called the “repeat fishing tool” by some field hands.

When open-hole logging and other tests are done, the operator must decide how to proceed. Even though a substantial amount of data has been obtained, the risk of a wrong choice has not been eliminated.

Setting Production Casing: Completion

If the well is to be abandoned after careful analysis of the data, then the process will involve setting plugs and pumping cement to seal the well. If, on the other hand, a choice is made to case and complete the well, then one sets the production casing with the drilling rig following procedures similar to those used for setting surface casing. Whether plugged or cased, it is time to ‘rig down and move out (RDMO)’ to the next drilling location.

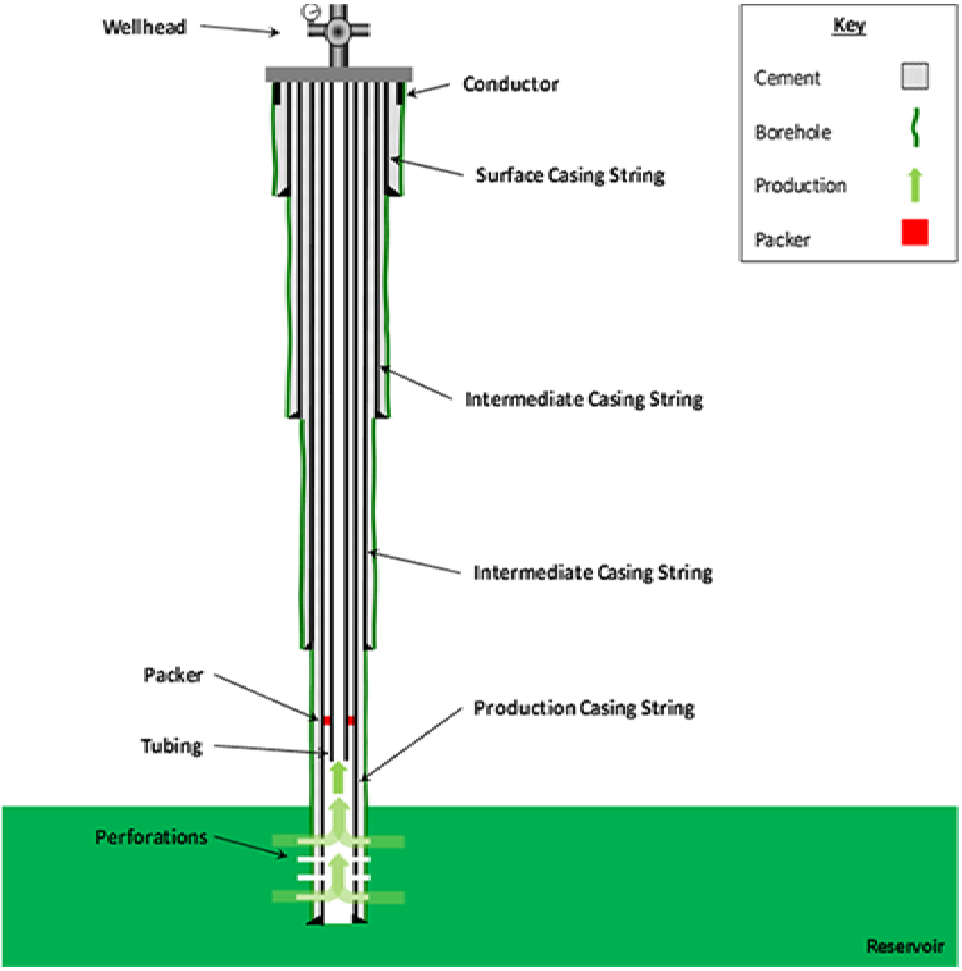


Figure 10 shows a wellbore diagram for a vertical well.

Casing prevents fluid movement between formations and it prevents collapse of the wellbore. Surface casing fits inside the conductor pipe and protects freshwater formations. Some wells have one or more strings of intermediate casing inside the surface casing, each with a smaller diameter. Intermediate casing protects formations above the target zone. Intermediate casing may go most of the way to total depth. Production casing has the smallest diameter. Production or injection tubing must be able to fit inside the production casing. Casing is set with cement to attach the casing to the formation and to prevent fluid movement behind the casing. Cement leaks or fractures in the cement are possible. The cement must be tested to ensure it is functioning properly before the well is completed. During the completion stage, perforations (holes) must be punched through casing at the target formation to allow fluids to flow into the production tubing.

Casing is tested by the manufacturer to determine its ability to withstand the forces that will act on it. Tension forces pull at the top of the casing, collapse forces push against the outside of the casing, and burst forces from fluids in the casing push against the inside. The casing and casing joints must not split or separate during high-pressure fluid injection because the breach would lead to contamination of formations.

Summary of The Drilling Process

1. Plan the Well: As explained. Exploration well prospects are generated by exploration geologists; while development wells locations and objectives are generated by development geologists

2. Perform Shallow Gas Survey: To ensure there are no shallow gas hazards which may result in a kick or blow out, a shallow gas survey is performed to identify the locations and depths of any potential shallow gas hazards. Preliminary surface locations and well trajectories may be altered from the original well proposal to avoid these shallow gas hazards.

3. Prepare the Wellsite: As explained. This depend on whether the drilling is offshore or onshore.

4. Set the Conductor Casing: As explained. A hole is drilled to accommodate a large diameter conductor pipe of 18 in. to 36 in.

5. Move-In and Rig Up (MIRU): Once the wellsite is prepared and the conductor casing is in-place, the rig is brought on location. Most land rigs, particularly those in North America, are transported on multiple trucks. Once on the well site or well pad, the rigging-up process begins. Rigging up the well consists of taking the rig modules from the trucks and assembling the rig. Included in the rigging up process is setting-up all of the rig systems and testing these systems.

6. Spud the Well: After the rig has been inspected and all of the systems tested the well can be Spudded. Spudding a Well refers to starting the rotary drilling operations for that well.

7. Drill Down to the Surface Casing Depth: The first section of the well to be drilled is the section that goes down to the pre-determined surface casing depth (Casing Point). Obviously, for this section of the wellbore, the drill bit diameter must be smaller than the ID (inner diameter) of the conductor casing. In this shallow section of the wellbore, fresh water aquifers (both for personal and municipal use) exist. As discussed earlier, shallow gas hazards may also exit. The objective of drilling this first section of the well is to allow the setting and cementing of the surface casing to:

Protect the fresh water aquifers by placing a steel and concrete barrier to isolate the water table from the well

Protect the well from the aquifer (cutting of the drilling fluids with fresh water)

Protect the well from shallow gas hazards

This section of the well is drilled through the most environmentally sensitive depths. Consequently, when this section of the hole is drilled, it is typically drilled with the most environmentally friendly drilling fluid (possibly either air or fresh water) and cased and cemented as soon as possible to alleviate any potential of contaminating fresh water aquifers. By running the surface casing string, we are putting the environmentally sensitive water table behind pipe, and protecting it from future well (drilling and production) activities.

8. Run and Cement the Surface Casing: Once the surface casing point is reached, the surface casing is run into the wellbore and cemented into place. This process is performed by:

- Pulling Out of Hole (POOH): Tripping out of the hole with the drill pipe to remove it from the wellbore during cementing operation
- Running the surface casing
- Pumping a cement slurry down the interior of the casing
- Chasing the cement with drilling fluid to displace the cement up into the annular space between the casing string and the wellbore (rock)
- Allowing time for the cement to Cure (harden)

9. Continue this Process to Drill to the Next Casing Point: This drilling process is continued to the next pre-determined casing point. The objectives of the intermediate casing strings are:

- ✓ Isolate unstable hole sections behind pip
- ✓ Isolate lost circulation zones behind pipe
- ✓ Isolate under-pressured zones behind pipe (prevent lost circulation)
- ✓ Isolate over-pressured zones behind pipe (prevent a kick)
- ✓ Isolate multiple producing zones

10. Continue this Process to Drill to each Casing Point: This process is repeated for each of the planned casing points. Smaller diameter tools and drill bits must be used for continued drilling operations. The two most important drilling parameters within the Driller’s control to maximize the Rate of Penetration (ROP) of the drill bit are the weight-on-bit and the rotational speed of the rotary system in Revolutions per Minute (RPM).

11. Continue this Process to Drill to Total Depth (TD): Once the final intermediate casing string is run and cemented, the drilling process is continued until the well reaches the TD (Total Depth) of the well. At this point, the well is said to be TD’ed.

12. Log the Well with Open-Hole Logs: At this point, the sand face is exposed to the well and Open-Hole Logging Tools can be run in the well. Open-hole logs are used to measure certain properties of the subsurface formation that are of interest to the geologists and engineers working on the well and the reservoir.

13. Run and Cement the Production Casing String or Liner: If a production casing string or production liner is to be used in the completion, then they are run and cemented at this time.

14. Compete the Well: Install the well completion as discussed in earlier lessons:

- Tubing Gravel packs

- Packers
- Sliding sleeves
- Stimulation
- Acidize the well by:

  - Hydraulically fracturing the well
  - ii. Artificial lift

15. Rig Down and Move Out

WELL CONTROL SYSTEM

The defense mechanisms set against blowouts are:

- Mud of proper weight
- The blowout preventer (BOP),
- The kill line,
- The choke line and,
- Choke manifold.

The BOP is used to shut in the well in emergencies. As shown in Figure 8.9, the BOP is a stacked sequence of two to four hydraulically actuated valves or preventers. The top preventer is an annular preventer, which functions much like a rubber sleeve for measuring blood pressure. The annular preventer can squeeze around the drill pipe or the **KELLY** to close the annular space. The next preventer is a pair of pipe rams that slide from opposite sides of the BOP to close around a pipe. The half-circle sealing elements on the pipe rams must have the same diameter as the pipe in order to properly seal. Blind rams are designed to close an open hole and cannot shut the well if the pipe is in the hole. The final preventer is a shear ram. Shear rams are designed to cut any pipe in the hole and seal the well. The drilling crew installs the BOP on top of the casing head, which is attached to the top of the surface casing after it is cemented in place.cx

In addition to the BOP, a kill line and a choke line are connected at the wellhead. The kill line can be used to perform well integrity tests and to inject high-density mud into the wellbore to block fluid flow up the wellbore. The choke line has a choke manifold with various chokes in line. The choke line can be used to control wells that encounter higher pressures than the drilling fluid can contain. In this case, the well is out of balance because the formation pressure exceeds the hydrostatic pressure exerted by the drilling fluid and the chokes release pressurized fluids in a controlled manner. To resume normal drilling, the drilling crew circulates heavier mud down the drill pipe and up the annulus. The hydrostatic pressure exerted by the heavier mud should exceed the formation pressure and normal drilling can resume.

Workover

This is the repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons, i.e., the process of performing major maintenance or remedial treatments on an oil or gas well. In many cases, workover implies the **removal and replacement of the production tubing string** after the well has been **killed** and a workover rig has been placed on location. Through-tubing workover operations, using coiled tubing, snubbing or slickline equipment, are routinely conducted to complete treatments or well service activities that avoid a full workover where the tubing is removed. This operation saves considerable time and expense. Workovers are done through the lifetime of the well.

The majority of workovers are done because the well is not performing up to expectations. Careful analysis will determine if the decline is abnormal or the result of normal reservoir depletion. If deemed abnormal, it must be determined if the problem is in the reservoir inflow system, the wellbore outflow system, or both. Inflow problems can be corrected with stimulation procedures such as acidizing, fracturing, scale, or paraffin treatments or by re-perforating or additional perforating. Outflow problem resolution may require equipment changes, cleanouts, or chemical treatments.

Mechanical problems such as failures of the cement, tubulars, packers, wireline components, safety valves, or artificial lift equipment are also reflected in the well performance. Cement and casing problems are most often corrected by squeezing cement into the damaged areas. Very serious problems of this nature occasionally require a sidetracking operation. Depending on the initial wellbore configuration, some mechanical problems can be corrected by applying wireline methods. More often, however, the equipment must be pulled using a rig. This may be a routine operation, but it may be a major task if the equipment is stuck or has parted downhole. To recover parted or stuck downhole equipment, a fishing operation may be required.

Initiation of supplemental recovery projects causes workovers because many wells must be converted to injectors, observation wells, or disposal wells. Also, all wells need to be completed in correlative zones, thus a significant number of wells need perforating and stimulation and/or zones shutoff via squeeze cementing or plugs (cement or mechanical).

Workovers done for the reasons just noted are generally completed to yield a profit in a reasonable length of time. Those done for the following reasons may have little profit incentive, but are still necessary for prudent, legal operations:

Reasons for Workovers

1. **Regulatory requirements**: This may initiate workovers to reduce GORs, isolate pressures, or install safety equipment.
2. **Competitive conditions:** This may occasionally generate workovers designed to protect correlative rights, which often affects the timing more than the goal of doing that particular job.
3. **Reservoir Data Gathering**: particular special reservoir information (such as pressures, fluid samples and zonal productivity/injectivity tests) required for reservoir management or in connection with pilot tests, may require a workover.
4. **Lease Requirements**: The requirement to maintain production to hold a lease may encourage a workover to allow more time to determine proper lease disposition.
5. **Abandonment:** Workovers are normally required to temporarily abandon or to plug and abandon a well. Operations may include squeeze cementing, setting plugs (cement or mechanical), retrieving production equipment, and perhaps cutting and

pulling casing. Workover costs vary depending on well conditions and regulatory requirements.

6. **Unsatisfactory production or injection rates**
7. **Supplemental recovery project requirements**

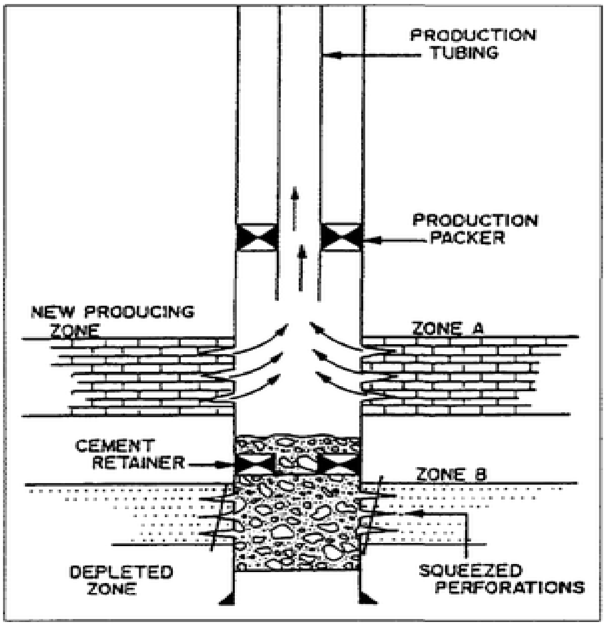


Figure 12 Recompletion

Types of workovers

Workovers are classified on the basis

- Reasons for them.
- Jobs performed primarily to influence the reservoir and,
- Jobs applied to the wellbore (including the cement) and its associated equipment.

Workovers done primarily to influence the reservoir can be subdivided into

- work done for the zone already open
- work done to shut off the existing zone in favor of opening a new zone, termed a recompletion.

Operations typically done in an existing zone may include stimulation, re-perforating, perforating additional intervals, and plugging off unwanted perforations (because of high gas or water production).

Recompletion work varies depending on whether the new zone is above or below the currently open zone. If above, the lower zone will be abandoned via squeeze cementing, a cement plug, or a mechanical bridge plug, and the zone of interest will be perforated and stimulated. Appropriate outflow equipment will then be installed. If the new zone is below, the existing zone will probably be squeeze cemented (in the same manner as repairing casing. The cement in the wellbore is drilled out, the lower zone perforated and stimulated, and production equipment run. Some wells have had sufficient well work done upon initial completion to permit recompletion by simply using a wireline to run plugs and open sleeves.

Wellbore workovers can include casing or equipment repair, but may also simply involve cleaning out fill over the producing zone or circulating chemicals to remove scale or paraffin.

Many workovers involve the installation, maintenance, and repair of artificial lift equipment in the wellbore. About 85% of the oil wells in the United States are on some form of artificial lift. Approximately 85% of those wells are on rod pump, 10% on gas lift, and 5% on submersible or hydraulic pumps. Rigs are required for most artificial lift workovers; however, many gas lift wells can be serviced with a wireline.

Workover Equipment

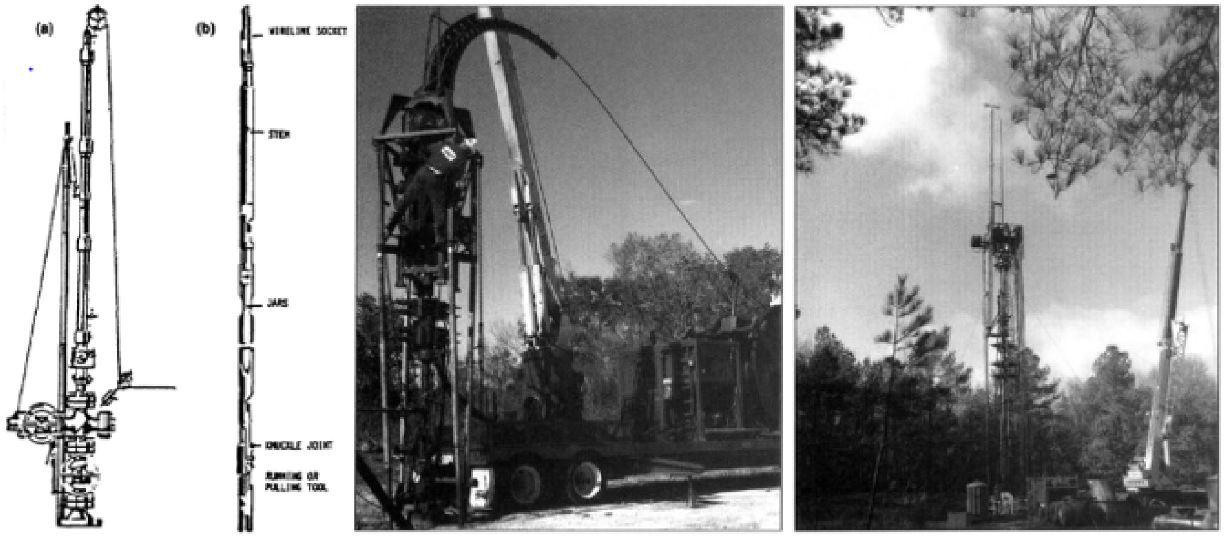


Figure 13 Wireline equipment{(a) Lubricator & Typical string}, Coiled tubing unit, and Snubbing unit.

Workovers can be done with

1. conventional rigs (smaller but similar to drilling rigs) or,
2. nonconventional systems.

Conventional rigs can be equipped to handle almost all types of work that may be required. Nonconventional systems allow specific types of work to be done without pulling the tubing, disassembling the Christmas tree, or even killing the well. This is accomplished by using lubricators and pack-off equipment at the surface and by running the required equipment inside the production tubing. Common types of nonconventional systems are wireline units, coiled tubing units, and snubbing units. Generally, these systems are designed to do a relatively narrow scope of work.

Wireline units use special equipment on a solid wireline to gather data (pressure, temperature, and depth) and to set, manipulate, and/or retrieve tubing plugs, sliding sleeves, flow regulators, gas lift valves, safety valves, and wireline fishing tools. Wireline equipment can also be used to cut paraffin and remove wellbore fill. Prior planning, good operators, good equipment, and reasonable well conditions are prerequisites to the success of this method.

Coiled tubing units find application in cleanout work, stimulation, plug back jobs, and unloading wells with nitrogen. Coiled tubing units can have 10,000 to 15,000 ft of pipe (usually 1 in. outside diameter) that can be reeled continuously into the wellbore. The pipe can be used to pump into the well and circulate fluids such as water, acid, or cement. The use of a dyna-drill permits some drilling with coiled tubing. Limitations of coiled tubing include the reduced strength of the tubing and low pumping rates (high friction pressure because of the diameter and length). Coiled tubing can be run into wells against pressures up to 5000 psi.

Snubbing units use hydraulic pressure and rams to introduce small, coupled tubing into the well, if necessary, against pressures above 5000 psi. The tubing is stronger and can be rotated so that tougher cleanout or fishing jobs can be accomplished. Snubbing units are used for the same type of jobs as are coiled tubing units, but their compactness is an advantage in offshore work. They are slow and expensive, but in the right applications, they are the more economical way to accomplish the task.

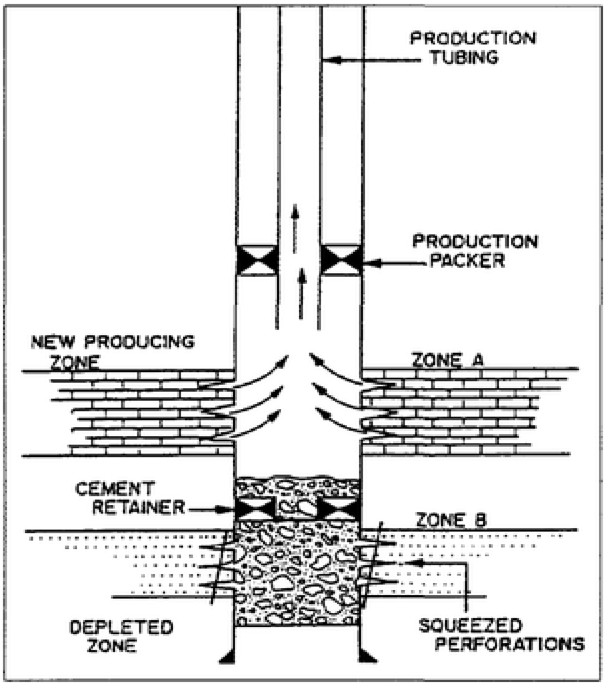


Figure 12 Recompletion

Types of workovers

To some degree, workovers are classified on the basis of the reasons for them. Another way to describe types of workovers is to divide them into:

(1) Jobs performed primarily to influence the reservoir and

(2) Jobs applied to the wellbore (including the cement) and its associated equipment.

Workovers done primarily to influence the reservoir can be subdivided into

- work done for the zone already open
- work done to shut off the existing zone in favor of opening a new zone, termed a recompletion.

Operations typically done in an existing zone may include stimulation, re-perforating, perforating additional intervals, and plugging off unwanted perforations (because of high gas or water production).

Recompletion work varies depending on whether the new zone is above or below the currently open zone. If above, the lower zone will be abandoned via squeeze cementing, a cement plug, or a mechanical bridge plug, and the zone of interest will be perforated and stimulated. Appropriate outflow equipment will then be installed. If the new zone is below, the existing zone will probably be squeeze cemented (in the same manner as repairing casing. The cement in the wellbore is drilled out, the lower zone perforated and stimulated, and production equipment run. Some wells have had sufficient well work done upon initial completion to permit recompletion by simply using a wireline to run plugs and open sleeves.

Wellbore workovers can include casing or equipment repair, but may also simply involve cleaning out fill over the producing zone or circulating chemicals to remove scale or paraffin.

Many workovers involve the installation, maintenance, and repair of artificial lift equipment in the wellbore. About 85% of the oil wells in the United States are on some form of artificial lift. Approximately 85% of those wells are on rod pump, 10% on gas lift, and 5% on submersible or hydraulic pumps. Rigs are required for most artificial lift workovers; however, many gas lift wells can be serviced with a wireline.

WELL COMPLETION/DESIGN

Well completion is defined as a single operation involving the installation of production casing and equipment in order to bring the well into production from one or more zones

The well completion is the lowermost portion of the well, comprised of tubulars and downhole equipment, that enables the safe and effective production from an oil or gas well. The objectives of the completion are to:

- Connect the reservoir to the production tubing;
- Provide a conduit for well stimulation fluids;
- Protect the well from sand/fines production;
- Isolate productive zones from non-producing zones;
    - isolate oil producing zones from high GOR (gas-oil ratio) and high watercut zones in oil reservoirs;
    - isolate gas producing zones from high GLR (gas-liquid ratio) zone in gas reservoirs;
- Provide a means to measure changes in reservoir conditions (pressure, saturation, rate) by well tests, cased-hole logs, and production logs.

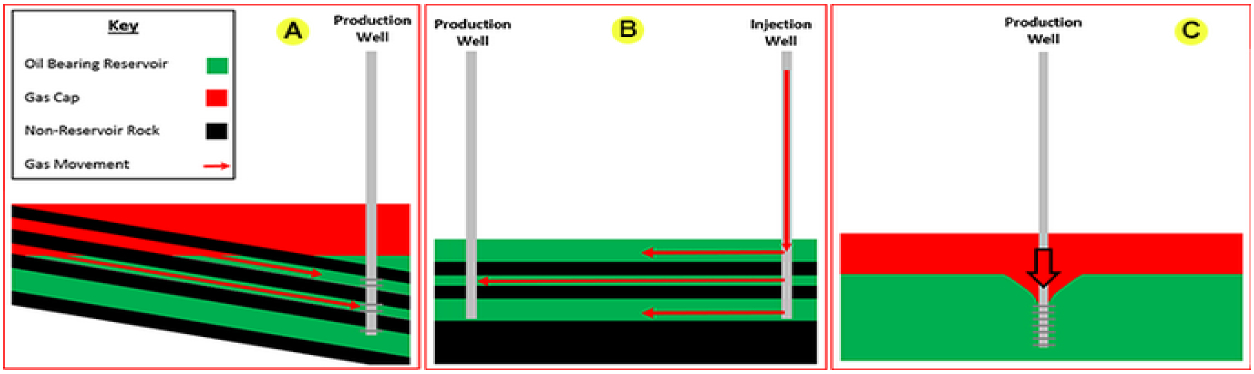
TYPES OF COMPLETIONS

There are many types of completions, however, we will focus on the following:

- ***Open-Hole*** or ***Bare Foot*** completion
- ***Screen*** or ***Liner*** completion
    - ***Slotted Liner*** completion
    - ***Screen*** completion
    - ***Gravel pack*** completion
- ***Cased and Perforated*** completion

1. Open Hole and Barefoot Completion

The least complex and least costly well completion is a ***Barefoot***, ***Open-Hole*** completion. An open-hole completion is a completion that does not have any casing or tubulars cemented across the reservoir section, while a barefoot completion has no tubulars, casing or tubing, across the reservoir section (a barefoot completion is a subset of an open-hole completion). Two examples of barefoot, open-hole completions are shown in '**just below**,' one without tubing and one with tubing.



The advantages of a barefoot, open-hole completion include:

- They are the least expensive completion technique;
- They are adaptable to special drilling techniques that minimize reservoir damage (wells can be drilled to the top of the reservoir, casing set and cemented in place, and drilling/completion fluids changed to less damaging fluids for drilling through

the reservoir);
- No perforating expenses;
- No issues with open-hole logging (time-lapse open-hole logs can be run for improved reservoir characterization and surveillance);
- Large wellbore radius, r_w, across the reservoir (From Lesson 4 and Lesson 5, we saw that a large wellbore radius improves ***Productivity Index*** and ***Inflow Performance*** – **Table 7.01** and **Table 7.02** have been reproduced to illustrate this point and to aid in later discussions);
- Large diameter conduit to surface which results in lower pressure losses in high production rate wells (in Lesson 6, we saw that the pressure losses were significantly impacted by the D_{ID} the inner diameter of the conduit to the flow);
- The well can be easily deepened if desired;
- The completion can be modified at a later date with an inner casing string or liner if desired.

The disadvantages of a barefoot, open-hole completion include:

- As illustrated, sand production cannot be permanently controlled without a ***Major Rig Workover***, ***MRWO*** (an expensive well intervention requiring a drilling rig and hoist). Temporary sand control can be performed with multiple bailer/clean-out well interventions (less expensive ***Slickline Workover***). We will discuss ***Major Rig Workovers***, ***Coiled Tubing Workovers***, ***Wireline Workovers***, and ***Slickline Workovers*** later in this lesson;
- As illustrated, excessive gas or water production cannot be easily controlled;
- Selective well stimulation (acidizing or hydraulic fracturing of specific depth(s) in the reservoir) more difficult than with ***Cased and Perforated Completions***;
- While the large diameter conduit for fluids flowing to the surface has the advantage of lower pressure losses, it has the disadvantage of lower velocity for the same volumetric rate. If the velocity of multiphase flow is too low, then the heavier fluids may segregate toward the bottom of the well causing a segregated water phase across the reservoir.

manipulation

Exceptional features of switch wettability between hydrophilicity and hydrophobicity triggered by by external stimuli especially, also

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