COURSE CONTENTS: REVIEW ON

1. PETROLEUM GEOLOGY: Formation/ occurrence of Petroleum i.e (hydrocarbons, Origins, Migration of Petroleum, Reservoir Rocks, Oil Traps and Accumulation of Petroleum)

2. Exploration methods: - Regional prospecting and prospecting drilling.

3. Reservoir: Types of oil and gas reservoirs, Reservoir rock and fluid properties, Reservoir pressures; Reservoir Evaluation (e.g volumetric reservoir estimate; behaviour of reservoir fluids, depletion and conservation.

4. Drilling: Drilling history, types of drilling rigs, drilling equipment – hoisting function, rotary system, drill string, circulation system and drilling fluids; blowout prevention and equipment, casing and cementing; directional drilling

(1) PETROLEUM GEOLOGY

Origin of Petroleum

Hydrocarbon is a natural organic substance composed mainly of Hydrogen (H) and Carbon (C). Early life began in vast seas and inland lakes that covered large proportions of the present continents. As the abundant populations of marine plant and animal life died, their remains were buried rapidly and preserved in the silt and mud that continuously filtered down to the ocean floor (Fig. 1.1).
Figure 1.1: As plants and animal die, they fall to the seafloor and are buried in sand, silt and mud (Forrest Grey, 1986)

Organic materials generated from these sediments are the source of the hydrocarbons. As sediments are buried, temperature and pressure increase, and the organic rock fragments undergo chemical and physical changes that result in formation of oil and gas and excess formation pressure. Maturation is the complex process through which biological molecules, created by living organisms, are converted into petroleum. In the early stages of this alteration, or diagenesis (Diagenesis is the chemical and mechanical alteration of a rock after burial. An example is the replacement of some of the calcium atoms in limestone by magnesium to form dolomite)

Figure 1.2: Diagenesis- replacement of some of the calcium atoms in limestone by magnesium to form dolomite.

an intermediate form of organic matter, called kerogen, is formed. Kerogen is created by the breakdown of complex biological molecules, reactions between some of the newly created simpler molecules, and the loss of most non-hydrogen and carbon atoms like NH$_3$, CO$_2$ and H$_2$O. Microscopically, kerogen can be seen as yellow-orange to brown-black particles or amorphous material. Since this material originated from different kinds of
living organisms, with different kinds and proportions of biological molecules, kerogens will not all have the same chemical compositions and will yield different types and amounts of petroleum. Geologists have found it convenient to group kerogens into four fundamentally different classes (Figure 1.3). Type I kerogen is derived mostly from the remains of algae, and when it matures it yields mainly crude oil. It is also capable of generating the most petroleum of all the kerogen types. Type II kerogen consists mostly of amorphous material, derived from the bacterial and mechanical breakdown of a mixture of marine, one-celled plants and animals. This kerogen is also oil-prone but yields more natural gas than Type I. Type III kerogen, derived from the higher land plants, is sometimes known as coaly kerogen. The humic material in Type III kerogen has a low capacity to form oil and yields mostly natural gas. Type IV kerogen consists mostly of inert particles that have been highly oxidized before burial, like charcoal. It is the rarest kerogen type and has practically no ability to generate either oil or gas.

The chemistry of crude oil can also be linked to kerogen type and original organic matter. Usually land-derived, non-marine organic matter deposited near continental drainage areas (Type III coaly kerogen) will form mostly gas, but any oil formed will be low sulfur, paraffinic to paraffinic-naphthenic crude oils. Marine organic matter, particularly protein-rich types derived from marine animals (Type II mixed marine kerogen) tends to yield high sulfur aromatic-intermediate crude 

![Diagram of Kerogen types](image)

Figure 1.3: Kerogen types
Petroleum Generation

Petroleum is generated when kerogen is subjected to the increased temperatures that accompany sediment burial. The alteration of kerogen to petroleum is similar to other thermal cracking reactions. Large kerogen molecules decompose upon heating, to yield smaller molecules of petroleum. These reactions usually require temperatures greater than 60 °C. At lower temperatures, during early diagenesis, natural gas, (called biogenic methane or marsh gas) is generated through the action of microorganisms that live near the earth's surface. Vast quantities of biogenic methane are probably generated, but most of this will not encounter a trap and will be lost to the atmosphere.

The temperature range between about 60°C and 175°C is commonly called the oil window (Figure 1.4). This is the principle zone of oil formation. It begins at burial depths of 1 to 2 km and ends at depths of 3 to 4 km in most areas, depending on factors such as the geothermal gradient. The first oil generated is heavy and tends to be richest in aromatic and resin compounds. As burial and temperature increases, the oil becomes lighter and more paraffinic. At temperatures much above 175°C, the generation of liquid petroleum ceases and gas formation becomes dominant. When formation temperatures exceed 225°C, most kerogen has used up its petroleum-generating capacity. Source rocks become over-mature. However, some methane can still be created, even at these very high temperatures, by the breakdown of the larger, heavier molecules of previously generated crude oil.

Figure 1.4: Oil window
Hydrocarbon Migration

The movement of petroleum from source rock to reservoir rock and within reservoir rock into oil pools is called migration. Hydrocarbon migration takes place in two stages:

- **Primary migration** - movement from the source rock to a porous rock.

  This is a complex process and not fully understood.

  It is probably limited to a few hundred metres.

- **Secondary migration** - movement along the porous rock to the trap.

  This occurs by buoyancy, capillary pressure and hydrodynamics through a continuous water-filled pore system. It can take place over large distances. Secondary migration is simple to understand with the higher hydrocarbon floating to rest on top of the original water. The primary part of the process is much more complex. The exact mechanism is uncertain as the experiment cannot be done in the laboratory (high temperature and pressure and a very long time).

![Figure 1.5: Petroleum migration and accumulation](image)
**Figure 1.6: Petroleum system processes**

**Source rocks** are any rocks in which sufficient organic matter to form petroleum has been accumulated, preserved, and thermally matured. Organic particles are usually fine-grained, and will settle out most easily in quiet-water environments. Therefore, source rocks are most commonly fine-grained rocks, particularly shales. Other potential sources are fine-grained carbonates (lime mud), mud-carbonate mixtures (marl), or coal.

**Reservoir rocks** are rocks having sufficient porosity ($\phi$) to contain reservoir fluids and permeability ($k$) to permit their movement.

**Hydrocarbon/Oil Traps**

In order for petroleum to accumulate, there has to be some trapping mechanism to contain the petroleum to form a pool. There are three major ways of trapping:

- Structural traps
- Stratigraphic traps
- Combination traps
Figure 1.7: Definition of trap components

The highest point of the trap is the **crest** or **culmination**. The lowest point is the **spill point**. A trap may or may not be full to the spill point. The horizontal plane through the spill point is called the **spill plane**. The vertical distance from the high point at the crest to the low point at the spill point is the **closure**. The productive reservoir is the pay. Its gross vertical interval is known as the **gross pay**. The key concepts are those of Net and Gross pay.

Gross pay is always > Net pay. This can also be described by the Net -to- Gross ratio which is always less than or equal to one.

The spill plane is the maximum level to which this particular reservoir can fill before the next anticline starts to be filled.

### Structural Hydrocarbon Traps
Structural traps describe all the large features and include domes, anticlines and faults. These large scale reservoirs include most of the Middle East giants. Structural traps are created by deformation of the rocks. They are caused when horizontal compressional forces deform the rock into folds e.g anticlines.

Another very common structural trap is the fault trap. The vertical displacement of the fault interrupts the continuity of the reservoir rock, moving a section of impermeable rock into position where it seals off the reservoir.

Salt in creating the domes also adds faults and fractures due to the extra pressures on the rocks. The traps around the dome are difficult to find as anything below the Salt is invisible on the surface seismic. (The contrast between the salt and anything else is too large). However they can be excellent reservoirs as the salts will have fractured them giving good permeability characteristics.

**Stratigraphic Traps**
Stratigraphic traps describe the traps associated with the depositional environment. Reefs, channels and bars are from specific environments. These are created as a direct result of their depositional environment and could be located by changes in the depositional conditions resulting in a lateral change in the physical and chemical properties of the sediments in terms of lithology. They can also be formed as a result of differing degrees of sediment transport and compaction.

**Unconformity**

Unconformities exist due to tectonic movements when a formation; an anticline in the diagram is eroded (it is above ground level). It is then buried and more sediments are added creating the seal and hence the reservoir.
Combination traps

Combination traps incorporate both deformational and depositional mechanisms (Figure 1.11). An example is an angular unconformity which requires several steps in its formation.

The reservoir rock is deposited and lithified in an ocean basin.

The formations are pushed above sea level and tilted

A horizontal erosional surface develops on the tilted formations.

The erosional surface sinks below the ocean’s surface and horizontal shale deposition covers the exposed ends of the formations.

The shale lithifies and becomes the cap rock for the tilted reservoir rock.
Traps General

Seals

Traps must be sealed by impermeable barriers in order to stop the continued upward migration of petroleum. In the case of anticlines (Figure 1.13 (a)), only a vertical seal, or caprock, is required; but faults (Figure 1.13(b)), stratigraphic traps (Figure 1.13, (c)) and unconformity traps (Figure 1.13(d)) must be sealed both vertically and laterally. Shale is the dominant caprock of worldwide reserves and is overwhelmingly the seal in most sedimentary basins, where sandstones are the dominant reservoir rock.
Essential elements of hydrocarbon reservoir

In order to have a hydrocarbon producing reservoir, the following conditions must exist:

1. There must be a body of rock having sufficient porosity ($\phi$) to contain reservoir fluids and permeability ($k$) to permit their movement.

2. The rocks must contain hydrocarbons in commercial quantities.

3. There must be some natural driving force within the reservoir, usually gas or water, to allow the fluids to move to the surface.

Special attention must be given to #3. Oil in itself does not have a stored force or energy; that is, it cannot move itself. The only stored energy in the reservoir is in the form of gas or water under pressure which can move the oil into the wellbore. When this energy has been spent, only the slow method of gravity drainage remains to move the oil into the wellbore. However, gravity does not always work efficiently to move oil in the right direction to reach a wellbore.
The petroleum system

Figure 1.14: A petroleum system

Five factors are the critical to petroleum accumulation:

(1) A mature source rock

(2) A migration path connecting source rock to reservoir rock

(3) A reservoir rock that is both porous and permeable

(4) A trap

(5) An impermeable seal.

If any one of these factors is missing or inadequate, the prospect will be dry and the exploration effort will be unrewarded.
(2) EXPLORATION METHODS

Assessing Prospective Regions

The crucial judgement for an exploration company is deciding whether an unexplored area is or is not a prospective region. If it is supposed to be prospective, but turns out not to be, much time and money will have been wasted. If the unexplored province is supposed to be non-prospective, but it turns out to be prospective, the exploration company will have forfeited a chance for profit. A province is rarely written off, however, before some wildcats are drilled. Indeed, several dozen dry holes may be drilled before a province is called noncommercial.

Assessing prospectivity in producing regions is wholly different from that in frontier regions. In the former, you know you are in oil country, and the question is whether enough undrilled prospects remain between, beyond, above, and especially below known fields in order to justify further exploration. Much well information is usually available, and the main geological effort is geared toward answering local stratigraphic and structural questions before planning possible detailed geophysical surveys. On the other hand, in frontier provinces, the existence of the five essential factors (source rocks, reservoir rocks, migration paths, traps, and seals) for petroleum accumulation is a matter of speculation.

Many, if not most, of the world's remaining frontier provinces lie in offshore regions. Large untested provinces on land are apt to be in areas that are geographically or politically inaccessible.

Anomaly

Prospect generation begins with the search for anomalies. An anomaly may be defined as a deviation from whatever trend is normal. It's a local feature that can be distinguished within a larger area, because it has some kind of distinctive fingerprint which makes it stand out from the background data. The anomaly can be revealed by geologic mapping, geophysical or geochemical data, by biological and soil surveys, or by anything that departs from the norm.

The petroleum geologist knows that some anomalies are associated with deposits of commercially valuable oil and gas. The usual trend is for subsurface petroleum to make its way to the surface and eventually dissipate. In order to prevent further migration, there must be an anomaly present to act as a barrier. Geologists often regard anomalies as being broadly synonymous with structure, but anomalies are also associated with stratigraphic and other trap types. Often, more than one theory may account for an anomalous geological situation. If our aim is to generate the maximum number of prospects, it makes sense to use the most fruitful theory.

Lead

The likelihood of a commercial accumulation of hydrocarbons can be increased by the combined occurrence of one or more anomalies. This is called a lead. By doing additional exploration, a lead may either be transformed into a prospect (developing the lead), or it may be wiped out.

Prospect
An anomaly or a combination of anomalies becomes a bonafide prospect when it meets a stated set of criteria considered requisite for a commercial accumulation of hydrocarbons. Once the presence or at least the potential presence of a source rock is established, there are two basic criteria that must be met:

- The presence of a reservoir rock; and
- The presence of a trap of sufficient size to hold a commercial quantity of producible hydrocarbons.

From the viewpoint of the explorationist whose job is to pick a specific drill site, the presence of a trap is usually the more fundamental of the two, since it both locates and restricts the depth and areal position of the prospect. Also, it is usually the easiest factor to determine before a region has been drilled because potential traps can frequently be mapped through geological and geophysical surveys. However, many traps predicted by mapping have proved to be nonexistent after drilling. Poor well logs and samples, unsuspected facies changes, and faulty correlations all can lead to unreliable subsurface maps.

**Technical factors**

Assessing a frontier province begins with reconnaissance surveys on land, surface geology, coupled with photo-geology. This is followed by aeromagnetic surveys, then gravimetric surveys, and finally seismic surveys. In marine provinces, after an initial aeromagnetic survey is made, a reconnaissance seismic survey is customary. The purpose of the geophysical reconnaissance survey is to uncover the kinds, depths, magnitudes, and relative frequency of buried anomalies in the province and to appraise the sedimentary sequence. It would be desirable at this point to make a preliminary inventory of indicated volumes and depths of potential traps.

One or more of the most obvious of these anomalies is evaluated by detailed seismic surveys. The most promising is then selected for the initial wildcat test. In most cases, pronounced structural anomalies are the first to be tested. Until these initial tests are drilled in representative locations, it may be difficult to discern the practical significance of certain geophysical anomalies. Once drill cuttings, mud logs, and wireline logs are obtained from one or more wildcat wells, we can recognize the geological sequences present in the basin, detect hydrocarbon shows, and observe thickness and quality of reservoir strata. Moreover, it may be possible to determine the presence (or absence) of commercial source beds.

**Geophysical Methods**

- Gravity methods
- Magnetic surveys
- Seismic surveys
Of the above geophysical methods, seismic surveys have the highest resolution and are most useful in hydrocarbon exploration. Gravity and magnetic surveys commonly are used in reconnaissance surveys.

**Gravity methods**

Gravity surveys measure small changes in the earth’s gravity field caused by density contrasts between rock types. The tool is most effective when the density of the rock comprising geological structures differs markedly from the surrounding rock. For example, the density of the salt diapir differs from that of the surrounding clastic sedimentary rocks. The sensing element in the tool in gravity method is a sophisticated form of spring balance. Gravity measurements must be corrected for the elevation of the recording station. Gravity data may be used (in conjunction with magnetics) as a first pass exploration method.

**Principle of Magnetic Surveys**

The magnetic survey detects changes in the earth’s magnetic field caused by variations in the magnetic properties of rocks. For example, basement rocks are relatively highly magnetic, and those close to the surface give rise to short wavelength, high amplitude anomalies in the earth’s magnetic field. The method is airborne which permits rapid surveying and mapping with good areal coverage. Like the gravity technique, this survey is often employed at the beginning of an exploration project.

**Seismic Surveys**

The seismic tools commonly used in the oil and gas industry are 2-D and 3-D seismic data. Seismic data are used to:

- Define and map structural folds and faults
- Identify stratigraphic variations and map sedimentary facies
- Infer the presence of hydrocarbons

PETROLEUM EXPLORATION - EARLY SURFACE MAPPING
Figure 2.1: Stage of early mapping and reconnaissance geophysics

Petroleum exploration can be divided into a series of critical information phases. With each step, there is a progressively increasing data base, from which to evaluate the petroleum prospects of a region.

Phase I is the stage of early surface mapping and reconnaissance geophysics (Figure 2.1). It begins with the unexplored basin. To varying degrees, there may be some previous knowledge of surface geology and structures (formation outcrops – surface exposures of the underlying rocks). There may also have been reports of surface indications (e.g., surface seeps, springs, asphaltic vein-fillings, gas detected in water wells, etc.) to encourage the exploration. Surface evidence of petroleum has been important in the discovery of nearly every major onshore petroleum province in the world although there are also major areas with abundant surface evidence that have proven to be sub-commercial (e.g., Cuba and Morocco). At this stage, the geologist's role is to obtain a more detailed knowledge of surface structures (i.e., potential traps) and evaluate other aspects critical to the exploration task, such as sedimentary facies, possible metamorphism etc. The exploration geologist must work closely with the geophysicist to relate the surface stratigraphy and structures to the subsurface. At this stage, a geologic analog is often used to compare the unexplored basin to other producing "look-alike" basins which appear to have common geologic characteristics.

SEISMIC SURVEY
Phase II is the stage of seismic survey (Figure 2.2). Seismic survey uses explosives or other means to create miniature earthquakes that help locate structural traps – those formed by deformation of the rock formations. Anticlinal traps and fault traps are examples. (This is the initial step, in offshore exploration.) During this stage, more data is obtained on the depth configuration of potential traps and hopefully some knowledge of the character and volume of the sedimentary fill is gained. It has generally been observed that the chances of finding commercial oil is roughly in proportion to the total sediment volume, particularly if most of it lies within the depth range of the oil and gas window. The volume of subsurface shale (source potential) is also evaluated.

**WILDCAT DRILLING**

Phase III is the stage of exploratory or "wildcat" drilling, which establishes for the first time a detailed sampling of the sediment character (reservoir, source and caprock potential), maturation,
and the geothermal regime (Figure 2.3). The potential for a discovery exists at this stage, since the most promising prospects, usually surface or seismically detected subsurface structures are drilled first. However, even a dry hole is not necessarily a total failure. It can supply a large amount of data (e.g., sub-commercial shows; water-filled reservoir downdip from a possible pinchout, etc.) that, if intelligently studied, may lead to the placement of new wildcat wells.

**DISCOVERY PHASE**

![Diagram of discovery phase](image)

**Figure 2.4: Discovery phase**

Phase IV, the discovery phase, follows the successful completion of some wildcat wells (Figure 2.4). At this stage, reservoirs are established and hydrocarbon types may be linked to certain stratigraphic units and/or trap types. Further wildcat drilling in less developed parts of the basin may be guided in part by the play and petroleum zone concepts. A play is defined as a group of geologically similar, "look-alike" prospects, usually at fixed horizons sharing common stratigraphic features (lithology, unconformity). A basin may also be divisible into discrete petroleum zones. These are sediment volumes whose contained pools show several characteristics in common. Application of the play and petroleum zone concepts usually causes the success ratio of drilling (discovered fields/tested prospects; or barrels found/thickness drilled) to improve during the discovery stage. Many of the basin's largest fields will have been discovered, and exploration for more subtle traps may commence.

**PRODUCTION PHASE**
Phase V, the production phase, begins to provide exploration geologists with reserve estimates and a history of the hydrocarbon potential of the basin (Figure 2.5). There is enough information to work out field-size distribution patterns, which may help guide further exploration as the area matures. Commonly, not all of a sedimentary basin is at the same stage of drilling and development at the same time. Part of the basin may be maturely drilled, while other areas that may have appeared initially less geologically favored, or were less accessible, may still be only semi-mature or untested. Also, shallower depths may have been thoroughly tested and have established production, while at the same time deeper stratigraphic horizons may be only at the seismic survey or wildcat stages of development. It is significant that new discoveries are still being made in sedimentary basins where drilling and development have proceeded for 50 or more years.

Technical and Economic Risks in Exploration

There are a number of technical and economic risks involved in the exploration effort, such as the ability to recover the petroleum and the quality of the oil or gas. Less than 60%, and sometimes as low as 10% of the oil in the ground (oil-in-place) and 70% to 90% of the gas-in-place has proved economically recoverable by modern technology. The geological setting must be accurately assessed to optimize this recovery. Furthermore, in any petroleum basin, there will be some traps that are too small or reservoirs of too poor quality to pay back drilling and production costs. Assessors also need to be able to predict whether the product will be oil or gas, since in remote areas the added difficulties and handling costs of natural gas may be prohibitive. Similarly, it is often important to predict the chemistry of crude oils and natural gas mixtures, particularly in areas where the results may be only marginally commercial. These must all be, in part, considerations of the exploration geologist. At this point, the task may seem overwhelmingly difficult, but it is important to
remember that Nature follows rules and does not randomly distribute this petroleum beneath the earth's surface. Our understanding of these rules is based on numerous past lessons learned from the drilling of many successful wells and many dry holes. It is the application of these rules, to situations that are always somewhat unique, that is, the "art" within the science of petroleum geology.

(3) RESERVOIR

Types of Oil and Gas Reservoirs

Phase diagrams popularly known as pressure-temperature (P/T) diagrams help us to classify oil and gas reservoirs. To fully understand the significance of the P/T diagrams in the classification of reservoirs, it is necessary to identify and define the following key points on the P/T diagram (Figure 3.1)

- **Cricondentherm** ($T_{ct}$): The cricondentherm is the maximum temperature above which liquid cannot be formed regardless of pressure (point $E$). The corresponding pressure is termed the cricondentherm pressure, $p_{ct}$.
- **Cricondenbar** ($p_{cb}$): The cricondenbar is the maximum pressure above which no gas can be formed regardless of temperature (point $D$). The corresponding temperature is called the cricondenbar temperature, $T_{cb}$.
- **Critical point**: The critical point for a multicomponent mixture is referred to as the state of pressure and temperature at which all intensive properties of the gas and liquid phases are equal (point $C$). At the critical point, the corresponding pressure and temperature are called the critical pressure, $p_{c}$, and critical temperature, $T_{c}$, of the mixture.

**Phase envelope (two-phase region)**: The region enclosed by the bubble-point curve and the dew-point curve (line $BCA$), where gas and liquid coexist in equilibrium, is identified as the phase envelope of the hydrocarbon system.

- **Quality lines**: The dashed lines within the phase diagram are called quality lines. They describe the pressure and temperature conditions for equal volumes of liquids. Note that the quality lines converge at the critical point (point $C$).
- **Bubble-point curve**: The bubble-point curve (line $BC$) is defined as the line separating the liquid phase region from the two-phase region. **Bubble Point Pressure**: when a reservoir is above its bubble-point pressure, it has no free gas – all gas is in solution in the oil. As the reservoir is produced and pressure declines, the bubble-point pressure is reached. Gas comes out of solution, forming free gas saturation.

- **Dew-point curve**: The dew-point curve (line $AC$) is defined as the line separating the vapor phase region from the two-phase region. The “dew point,” defined as the temperature at which the natural gas is saturated with water vapor at a given pressure. At the dew point, natural gas is in equilibrium with liquid water; any decrease in temperature or increase in pressure will cause the water vapor to begin condensing.
Figure 3.1: A Pressure – temperature (p/T) diagram of hydrocarbons

Classification of oil and gas reservoirs

Depending on the initial reservoir condition in the phase diagram (Fig.3.1) hydrocarbon accumulations are classified as oil and gas reservoirs.

• **Oil reservoirs:** If the reservoir temperature, \( T \), is less than the critical temperature, \( T_c \), of the reservoir fluid, the reservoir is classified as an oil reservoir.

• **Gas reservoirs:** If the reservoir temperature is greater than the critical temperature of the hydrocarbon fluid, the reservoir is considered a gas reservoir.

Oil Reservoirs

Crude oil is the portion of petroleum that exists in the liquid phase in natural underground reservoirs and remains liquid at atmospheric conditions of temperature and pressure. Crude oil may contain small amounts of non-hydrocarbons produced with the liquids. Depending on initial reservoir pressure, \( p_i \), crude oil reservoirs can be sub-classified into the following categories:

1. **Under-saturated oil reservoir:** An oil reservoir that is at a pressure above its bubble-point pressure is called an under-saturated oil reservoir because it can dissolve more gas at the given temperature. As represented by point 1 on Figure 3.1, the initial reservoir pressure, \( p_i \), is greater than the bubble-point pressure, \( P_b \), of the reservoir fluid. Single (liquid)-phase flow prevails in an under-saturated oil reservoir.
2. **Saturated oil reservoir:** An oil reservoir that is at its bubble-point pressure is called a saturated oil reservoir because it can dissolve no more gas at the given temperature. As shown on Figure 3.1 by point 2, the initial reservoir pressure is equal to the bubble-point pressure of the reservoir fluid. A slight reduction in pressure brings about two-phase (liquid oil and free gas) flow exists in a saturated oil reservoir.

3. **Gas-cap reservoir:** If the initial reservoir pressure is below the bubble-point pressure of the reservoir fluid, as indicated by point 3 on Figure 3.1, the reservoir is a gas-cap or two-phase reservoir, in which an oil phase underlies the gas or vapor phase. There is free gas in the reservoir or gas cap.

**Gas Reservoirs**

Natural gas is the portion of petroleum that exists either in the gaseous phase, or in solution in crude oil, in natural underground reservoirs, and is gaseous at atmospheric pressure and temperature. Natural gas may include amounts of non-hydrocarbons such as nitrogen, carbon dioxide and hydrogen sulphide.

Natural gas may be sub-classified as **associated** or **non-associated** gas.

- Associated natural gas is found in contact with, or dissolved in, crude oil in a natural underground reservoir and includes solution gas and gas cap gas. A gas cap is free gas trapped in the top of the structure above the oil leg. When there is a gas cap, the reservoir is at bubble-point pressure.
- Non-associated natural gas is found in a natural underground reservoir that does not contain crude oil.

In general, if the reservoir temperature is above the critical temperature of the hydrocarbon system, the reservoir is classified as a natural gas reservoir. Natural gases can be categorized on the basis of their phase diagram and the prevailing reservoir condition into three categories:

1. **Dry gas reservoirs:** The hydrocarbon mixture exists as a gas both in the reservoir and the surface facilities. The only liquid associated with the gas from a dry gas reservoir is water.

2. **Wet gas reservoirs:** Because the reservoir temperature exceeds the cricondentherm of the hydrocarbon system, the reservoir fluid always remains in the vapour phase region at reservoir conditions. However, as the produced gas flows to the surface, the pressure and temperature of the gas decline. If the gas enters the two-phase region, a liquid phase condenses out of the gas and is produced from the surface separators.
3. **Retrograde condensate gas reservoirs:** If the reservoir temperature, $T$, lies between the critical temperature, $T_c$, and cricondentherm, $T_{ct}$, of the reservoir fluid, the reservoir is classified as a retrograde gas-condensate reservoir. Gas condensate reservoir production is predominantly gas from which more or less liquid is condensed in the surface separators.

![P/T diagram showing the positions of the different types of oil and gas reservoirs.](image)

Figure 3.2: P/T diagram showing the positions of the different types of oil and gas reservoirs.

Oil reservoirs can also be classified on the basis of boundary types, which determines driving mechanism, and which are as follows:

- Water-drive reservoir
- Gas-cap drive reservoir
- Dissolved-gas drive reservoir

**Water drive reservoirs**

Water-bearing rocks called aquifers surround nearly all hydrocarbon reservoirs. These aquifers maybe substantially larger than the oil or gas reservoirs they adjoin as to appear infinite in size, and they may be so small in size as to be negligible in their effect on reservoir performance. As reservoir fluids are produced and reservoir pressure declines, a pressure differential develops from the surrounding aquifer into the reservoir. Following the basic law of fluid flow in porous media, the aquifer reacts by encroaching across the original hydrocarbon–water contact.
In edge-water drive, as shown in Figure 3.4b, water moves into the flanks of the reservoir as a result of hydrocarbon production and pressure drop at the reservoir–aquifer boundary. The flow is essentially radial with negligible flow in the vertical direction. Bottom-water drive (figures 3.3 and 3.4b) occurs in reservoirs with large areal extent and a gentle dip where the reservoir–water contact completely underlies the reservoir. The flow is essentially radial and, in contrast to the edge-water drive, the bottom-water drive has significant vertical flow.

**Figure 3.3: A sketch of a water drive reservoir**

**Fig. 3.4a: Edge- water drive**

**Fig 3.4b: bottom- drive reservoirs**

**Gas cap drive reservoirs**

In a gas-cap drive reservoir, gas-cap drive is the drive mechanism where the gas in the reservoir has come out of solution and rises to the top of the reservoir to form a gas cap (Fig. 1.4). Thus, the oil below the gas cap can be produced. If the gas in the gas cap is taken out of the reservoir early in the production process, the reservoir pressure will decrease rapidly.
Sometimes an oil reservoir is subjected to both water and gas-cap drives as shown in figure 3.6.

**Dissolved gas drive reservoir**

A dissolved-gas drive reservoir (Fig. 3.7) is also called a ‘‘solution-gas drive reservoir’’ and ‘‘volumetric reservoir.’’
Dissolved-gas drive is the drive mechanism where the reservoir gas is held in solution in the oil. The reservoir gas is actually in a liquid form in a dissolved solution with the liquids from the reservoir. Compared to the water- and gascap-drive reservoirs, expansion of solution (dissolved) gas in the oil provides a weak driving mechanism in volumetric reservoir. In the regions where the oil pressure drops to below the bubble-point pressure, gas escapes from the oil and oil–gas two-phase flow exists.

RESERVOIR AND FLUID PROPERTIES

The key reservoir rock flow properties are:

1. Porosity
2. Permeability
3. Fluid Saturation

1. Porosity

Porosity is the first of two essential requirements for a rock to act as a hydrocarbon reservoir. It is simply a measurement of the pore or void spaces in a rock. Porosity can also be defined as the total void space as a measure of the total bulk volume of a permeable rock. Alternatively, it can be defined as the space or pores in a reservoir rock, which is not occupied. Porosity is often represented by the Greek letter phi (ϕ). It is usually expressed as a fraction or percentage using the formula:

\[
\text{Porosity (\%)} = \left( \frac{\text{volume of voids}}{\text{total volume of rock}} \right) \times 100
\]  

(3.1)

\[
\phi = \frac{v_p}{v_b}
\]  

(3.2)
Pore Volume $V_p = \text{Bulk Volume (} V_b \text{)} - \text{Grain Volume (} V_g \text{)}$

$$\emptyset = \frac{(V_b - V_g)}{V_b} = 1 - \frac{V_g}{V_b} \quad (3.3)$$

Any porosity less than five percent is very seldom commercial, and any porosity over thirty-five percent is extremely unusual. Porosity can be measured in the laboratory from cores and down the borehole using well logs, especially the sonic, density and neutron logs. Occasionally, it can be estimated from seismic data. The device used for measuring porosity is called “porosimeter”

**Types of porosity**

Porosity can be classified into various types according:

**Primary Porosity** – Formed during initial deposition of sediments.

**Secondary Porosity** – Formed after the initial deposition during the stage of diagenesis and is principally depended on the depositional environment. It is dictated by grain size, matrix cementation, grain shape, sorting, etc.

**Absolute Porosity** – This is a measure of the total pore spaces in a rock as a function of its bulk volume

**Effective Porosity** – This is a measure of the interconnected pore spaces in a reservoir rock as a function of its bulk volume. Hydrocarbon production requires that the fluid must migrate through the pore spaces in the reservoir rock before getting to the wellbore. Therefore from practical point of view, the effective porosity is the most important.

### 2 Permeability

This is defined as a measure of the ability of the permeable rock to transmit fluid. It is a measure of the ease of flow of a fluid through a porous medium. It is defined from the basic Darcy equation given as:

$$q = -\frac{kA}{\mu} \times \frac{\Delta P}{L} \quad (3.4a)$$

$q =$ Production rate, cm$^3$/sec

$k =$ Permeability, Darcy

$A =$ Cross section area, cm$^2$

$\Delta P/L =$ Pressure gradient (Pressure drop per unit length), atmosphere/cm
\[ \mu = \text{Fluid viscosity, centipoise (cp)} \]

**Permeability in field units**

\[ q \left( \frac{stb}{d} \right) = \frac{1.1271 \times 10^{-3}KA\Delta P}{\mu BL} \]  
(3.4b)

\( K \) (millidarcy); \( A \) (ft\(^2\)); \( \Delta P/L \) (psi/ft), \( B \) (rb/stb); \( \mu \) (cp)

**Types of Permeability**

**Effective Permeability**: This is the permeability of a rock to a particular fluid in the presence of a combination of fluids. There are

\[ k_o = \text{Effective permeability to oil} \]

\[ k_w = \text{Effective permeability to water} \]

\[ k_g = \text{Effective permeability to gas} \]

**Relative Permeability** \( k_r \): This is the ratio of effective permeability to a particular fluid as a measure of the absolute rock permeability. Oil Relative permeability can be defined as:

\[ K_{ro} = \frac{k_o}{k} \]  
(3.4c)

While gas and water relative permeabilities are defined respectively as:

\[ K_{rg} = \frac{k_g}{k} \]  
(3.4d)

\[ K_{rw} = \frac{k_w}{k} \]  
(3.4e)

Unit is dimensionless.

**Absolute Permeability**, \( K \): This is a measure of the ease of the flow of a single fluid through the porous medium with the fluid being the only reservoir fluid. Important mainly for experimental purposes where air or distilled water can be used.

The device used for measuring permeability is called **permeameter**.

---

3 Fluid Saturation

Usually, more than one fluid is present in a reservoir. Fluid saturation defines the extent or the percent volume of the reservoir pores occupied by a particular fluid. Therefore, fluid Saturation can be defined as the volume of a particular fluid as a measure of the total pore volume.
Water Saturation, \( S_w = \frac{V_w}{V_p} \)  

Oil saturation, \( S_o = \frac{V_o}{V_p} \)  

Gas saturation, \( S_g = \frac{V_g}{V_p} \)  

Where, \( V_w, V_o, V_g \) = volume occupied by water, oil and gas respectively;  

\[ V_p = \text{Pore volume} \]  

\[ V_o + V_g + V_w = V_p \]  

Note: \( S_o + S_w + S_g = 1 \)  

### Some key reservoir fluid Properties include

#### Density of oil

“Density of oil” is defined as the mass of oil per unit volume, or lbm/ft\(^3\) in U.S. Field unit. The density of oil at standard condition (stock tank oil) is evaluated by API gravity. The relationship between the density of stock tank oil and API gravity is given through the following relations:

\[ {^o}\text{API} = \frac{141.5}{\gamma_o} - 131.5 \]  

Specific gravity (SG) of a liquid is the ratio of the density of the liquid at 60°F to the density of pure water. SG for crude oil is given by:

\[ \gamma_o = \frac{\rho_{o, st}}{\rho_w} \]  

\( {^o}\text{API} \) = API gravity of stock tank oil  
\( \gamma_o \) = Specific gravity of stock tank oil, 1 for fresh water.  
\( \rho_{o, st} \) = density of stock tank oil, lbm/ ft\(^3\)  
\( \rho_w \) = density of freshwater, 62.4 lbm/ ft\(^3\)

#### Formation Volume Factor of oil

Formation volume factor of oil (B) is defined as the volume occupied in the reservoir at the prevailing pressure and temperature by volume of oil in stock tank, plus its dissolved gas, that is,

\[ \text{Formation Volume Factor}, \quad B = \frac{V_R}{V_S} \]  

---

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\[ V_R = \text{Volume at reservoir conditions, in reservoir barrel (RB)} \]

\[ V_s = \text{Volume at standard conditions (Stock tank conditions), STB} \]

Unit = Reservoir bbls/Stock tank bbls

**Formation Volume Factor of Gas**

Gas formation volume factor is defined as the ratio of gas volume at reservoir condition to the gas volume at standard condition, that is,

\[ B_g = \frac{V_{res}}{V_{sc}} = \frac{p_{sc}}{p} \frac{T}{T_{sc}} \frac{z}{z_{sc}} = 0.0283 \frac{zT}{p} \]  \hspace{1cm} (3.9)

Where the unit of formation volume factor is \( \text{ft}^3/\text{scf} \).

**Solution Gas–Oil Ratio**

“Solution GOR” is defined as the amount of gas (in standard condition) that will dissolve in unit volume of oil when both are taken down to the reservoir at the prevailing pressure and temperature; that is,

\[ R_s = \frac{V_{gas}}{V_{oil}} \]  \hspace{1cm} (3.10)

Where,

- \( R_s \) = solution GOR (in scf/stb)
- \( V_{gas} \) = gas volume in standard condition (scf)
- \( V_{oil} \) = oil volume in stock tank condition (stb)

The standard condition is defined as 14.7 psia and 60°F. At a given reservoir temperature, solution GOR remains constant at pressures above bubble point. It drops as pressure reduces below bubble point. Solution GOR is measured in PVT laboratories.

**Reservoir Pressures**

The fluids in oil and gas reservoirs exist under pressure. When a well is drilled into a reservoir, it creates a conduit to the surface. The pressure differential between reservoir and the surface then drives reservoir fluids horizontally through the reservoir to the wellbore and then vertically up to the hole. Reservoir pressure is therefore the principal reservoir drive mechanism or source of energy for production hydrocarbons.

Reservoir pressure also influences the quantity of hydrocarbons present in the reservoir – particularly in the case of gas because of its compressibility. If a gas reservoir is at twice the pressure of another gas reservoir, it will contain roughly twice as much gas in the same amount of pore space.
Reservoir pressure is also of concern to drillers. If they drill into a reservoir with the weight of their drilling mud less than the reservoir pressure, a blowout can occur.

Reservoir engineering calculations require a value for the pressure in the reservoir, away from the wellbore. To obtain this value, the well must be shut in and the pressure increase with shut-in time must be recorded. We refer to this as a pressure buildup test. From these data the average pressure value is calculated. Bottom hole pressure (BHP) surveys are carried out in wells to obtain pressure data to define local and average reservoir pressures.

Reservoir Evaluation

Reserves Estimation

The term "reserves" means different things to different people. To the banker, reserves are the amount of capital retained to meet probable future demands. To the oil and gas operator, reserves are volumes of crude oil, natural gas, and associated products that can be recovered profitably in the future from subsurface reservoirs. Reserves are always estimated in oil and gas business.

Reasons for Reserve Estimates

Estimates of oil and gas reserves are required for different purposes by different segments of the industry and at different stages in the life of a particular oil and gas property. Segments of the industry concerned with oil and gas reserves include:

- companies and individuals responsible for exploration, development, and operation of oil and gas properties
- buyers and sellers of oil and gas properties
- banks and other financial institutions involved in the financing of exploration, development, or purchase of oil and gas properties
- agencies with regulatory or taxation authority over oil and gas operators
- investors in oil and gas companies

Methods of reserve estimation

Methods to estimate reserves are categorized here as:

1. Volumetric
2. Material balance

1 Volumetric Methods

Volumetric methods are used when subsurface geologic data are sufficient for mapping of the objective field or reservoir. One of the objectives of this mapping is to estimate oil and gas initially in place.
Volumetric Estimates of Initial Oil and Gas in Place

The concept of volumetric calculation of hydrocarbon in place is to determine the volume of fluid in the reservoir by measuring the areal extent of the reservoir, its average thickness, porosity and the hydrocarbon saturation. Hydrocarbon pore volumes are calculated using the equation below:

\[
HCPV = V\phi (1 - S_{wc}) \text{ or } Ah\phi (1 - S_{wc}) \quad \text{acre – ft} \tag{3.11}
\]

Where HCPV = total volume which can be filled with hydrocarbons either oil, gas or both.

\[
\begin{align*}
V\phi &= \text{pore volume (total volume in the reservoir which can be occupied by fluids) acre- ft} \\
S_{wc} &= \text{connate water saturation, fraction} \\
A &= \text{the areal extent of the reservoir, ft} \\
\phi &= \text{porosity, fraction} \\
1 - S_{wc} &= \text{the hydrocarbon saturation, fraction}
\end{align*}
\]

The oil industry uses a range of industry standard units, in which all calculations should be carried out. The volume of oil is measured in barrels, the amount of gas in cubic feet, thickness in feet, and area in acres. Conversions for these are given in Table 1 below.

<table>
<thead>
<tr>
<th>Table 1</th>
<th>Unit</th>
<th>Equivalent in foot- units</th>
<th>SI equivalents</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1 acre</td>
<td>43560 sq. ft</td>
<td>4047 m²</td>
</tr>
<tr>
<td></td>
<td>1 barrel</td>
<td>5.6154 cu.ft</td>
<td>159 litres</td>
</tr>
<tr>
<td></td>
<td>1 acre foot</td>
<td>43560 cu.ft = 7758 barrels</td>
<td>1233522 litres</td>
</tr>
</tbody>
</table>

Hence, for an oil zone of \( A \) acres and \( h \) feet thickness; the volume of original oil in place (OOIP) is

\[
OOIP = 7758Ah\phi (1 - S_{wc}) \text{ bbl} \tag{3.12}
\]

And for gas reservoir of the same dimension, the volume of gas originally in place (GOIP) is

\[
GOIP = 43560Ah\phi (1 - S_{wc}) \text{ cu. ft} \tag{3.13}
\]

Note that the oil and gas will be at raised temperature and pressure in the reservoir. The compressibility of oil and especially gas, and their coefficients of expansion with temperature mean that they will occupy different volumes at surface pressure and temperature conditions, or those present in the stock tank at the surface. For this reason reserves are often quoted corrected for the changes in temperature and pressure at the conditions of the stock tank. If this has been done, the stock tank oil and gas originally in place is given as STOOIP and STGOIP. The expansion or reduction in volume undergone by oil and gas as its temperature and pressure conditions change from that in the reservoir to that in the stock tank depend upon the changes in pressure and temperature and the composition of the oil or gas. The change is expressed by what are called formation volume factors. The oil formation volume factor \( B_o \) is the ratio of the...
volume of a standard mass of oil at reservoir conditions to that at stock tank conditions, and has no units. Hence, we can calculate now the amount of oil originally in place in the reservoir when measured at the pressure and temperature conditions prevailing in the stock tank (i.e., during production).

\[
STOIIP \text{ or } N = \frac{7758Ah\emptyset(1-S_{wc})}{B_{oi}} \text{ bbls}
\]

(3.14)

Where:

- \( N \) = Stock tank oil initially in place (STB)
- 7758 = barrels in an acre-foot
- \( A \) = area of the oil zone (acres)
- \( h \) = average net thickness of oil zone (ft)
- \( \emptyset \) = average porosity in the oil zone (fraction)
- \( S_{wc} \) = average water saturation in the oil zone (fraction)
- \( B_{oi} \) = initial formation volume factor (RB/STB)

For most practical applications, oil initially in place usually is rounded to the nearest thousand (MSTB) or million stock tank barrels (MMSTB).

Oil Example:

Area of zone, \( A = 2000 \) acres
Thickness, \( h = 150 \) ft
Porosity, \( \emptyset = 15\% \)
Water saturation, \( Sw = 30\% \)
Oil formation volume factor, \( B_o = 1.65 \) (reservoir bbl / stock tank bbl)

Calculate the OOIP and the STOIIP.

Solution:

\[
OOIP = 7758 \times 2000 \times 150 \times 0.15 \times (1 - 0.3) = 244,377,000 \text{ bbl} = 244.377 \text{ MMbbl}
\]

\[
STOIIP = \frac{7758 \times 2000 \times 150 \times 0.15 \times (1-0.3)}{1.65} = 148,107,272.7 \text{ bbl} = 148.107 \text{ MMbbl}
\]

Similarly, the gas formation volume factor \( B_g \) is the ratio of the volume of a standard mass of gas at reservoir conditions to that at stock tank conditions, and also has no units. Hence, we can calculate now the amount of gas originally in place in the reservoir when measured at the pressure and temperature conditions prevailing in the stock tank (i.e., during production).
\[ STGOIP = \frac{43560 A h \varnothing(1 - S_{wc})}{B_{gi}} \text{ SCF} \]  

Where,
\begin{align*}
43560 &= \text{cubic feet in an acre-foot} \\
A &= \text{area of gas cap or gas reservoir (acres)} \\
h &= \text{average net thickness of gas cap or gas reservoir (ft)} \\
\varnothing &= \text{porosity, fraction} \\
S_{wc} &= \text{connate water saturation, fraction} \\
B_{gi} &= \text{initial formation volume factor (CF/SCF)}
\end{align*}

For most practical applications, free gas initially in place usually is rounded to the nearest million standard cubic feet (MMSCF) or billion standard cubic feet (BSCF)

**Gas example/practice problem**

Area of zone, \( A = 2000 \text{ acres} \)
Thickness, \( h = 150 \text{ ft} \)
Porosity, \( \Phi = 15\% \)
Water saturation, \( Sw = 30\% \)
Gas formation volume factor, \( Bg = 0.0035 \text{ (reservoir cu.ft / SCF)} \)

Calculate the GOIP and STGOIP. Your answer should be in MMMSCF or BSCF.
Where $F$ = the productive zone or net pay ratio. For instance if the non-productive or shale zone is given as 1/5 of the total reservoir volume, $F = 4/5$ (fraction of clean or producible reservoir)

2. Material Balance Methods

If we visualize the reservoir as a "tank" of pressurized fluids, we may observe the changes in reservoir pressure and producing characteristics as fluids are produced, and thereby determine the type(s) of drive mechanism(s), in effect, the original volumes available, and the expected recovery. The material balance equation is the foundation of the reservoir engineer's analysis.
of a reservoir. Based on the law of conservation of mass converted to a volume relationship, it is simply expressed as:

\[
\text{Volume in} - \text{volume out} = \text{net change in volume.} \tag{3.16}
\]

This relationship can be restated in terms of reservoir quantities. For a given amount of production and the associated pressure change, the formula is as follows:

\[
\text{Reservoir Withdrawal} = \text{Expansion of oil and originally dissolved gas} + \text{Expansion of gas cap} + \text{Reduction in hydrocarbon pore volume due to rock and water expansion} + \text{Water influx} \tag{3.17}
\]

As a relationship between pressure drop and volume changes, the material balance equation is very valuable because it allows us to make an estimate of the original volume of hydrocarbons based on the Pressure-production performance. In order to apply the equation to determine OOIP we must have accurate historical production data for all fluids (oil, gas, and water), accurate historical bottomhole pressure data, pressure-volume-temperature (PVT) data representative of initial reservoir conditions, the compressibility of the reservoir rock and the relative size of any gas cap. A detailed discussion of material balance relationship will be done in your reservoir engineering class.

**Behaviour of reservoir fluids**

The understanding of the behaviour of any hydrocarbon system stems from the behaviour of the individual molecules making up that system. On the other hand, the behaviour of the hydrocarbon system is as a result of the responses or behaviour put forth by the system on application of and/or due to changes in Temperature and Pressure.

**Gas Reservoirs**

Gas reservoirs are hydrocarbon reservoirs that contain dry gas (i.e., the methane mole fraction is greater than 95%). Behavior of these reservoirs is governed by the gas equation of state and the material balance equation. Three quantities—pressure, volume, and temperature—define the state of a gas. Note that in most hydrocarbon reservoirs the temperature is considered to be constant.

**Gas Equations of State**

**Ideal Gas Equation:**
The **Ideal Gas Equation** of state is derived from Boyle’s law, Charles’ or Gay Lussacs’ law, and Avogadros’ law:

\[ pV = nRT \]  

(3.18)

where,

\( p \) = pressure, psia

\( V \) = volume, ft\(^3\)

\( n \) = number of pound-moles

\( R \) = gas constant = 10.732

\( T \) = temperature, °R = 460 + °F

While Equation ideal gas equation is used in many calculations not pertaining to hydrocarbon systems, it was found that the behavior of hydrocarbon systems deviates from the ideal or perfect gas law. The deviation from ideal behavior increases with pressure and decreases with temperature. This deviation is attributable to the fact that the perfect gas law assumes that the kinetic motion of gas molecules (i.e., their tendency to fly apart) is much stronger than the electrical attractive forces. This assumption is not valid at high pressure and relatively low temperature. Under most reservoir engineering pressure conditions, the molecules are brought close to each other, and the attractive forces become important. To correct for the deviation from ideal gas behavior, a gas deviation factor, or compressibility factor, is introduced into Equation 16. It becomes

\[ PV = znRT \]  

(3.19)

Where, \( z \) is the dimensionless deviation, or gas compressibility, factor.

**Oil Reservoir**

Crude oil behavior under varying conditions of pressure and temperature is (unfortunately) much more complex than the behavior of a dry gas. Gas consists primarily of methane and perhaps smaller amounts of the lighter hydrocarbons, while crude oil contains a larger percentage of the heavier hydrocarbons. Hydrocarbons are grouped into one of several molecular series depending on the relative amounts of carbon and hydrogen atoms making up their molecules. Paraffins (alkanes), naphthenes, and aromatics are the most common series, with paraffins predominating. Rather than define a reservoir according to its composition, the reservoir engineer will often give a broader classification range (Classification of oil reservoirs earlier discussed). Table 1 (below) gives another type of
classification, with typical ranges for composition, gravity, and gas-oil ratio. These categories are not rigidly defined and may vary according to local usage. Often the only classification given for a crude oil is based on its specific gravity (equation 10), which is relatively easy to measure on a small sample. Crude oil behaviour is governed by phase behaviour discussed earlier.

<table>
<thead>
<tr>
<th>Classification</th>
<th>GOR Range</th>
<th>API Gravity</th>
</tr>
</thead>
<tbody>
<tr>
<td>1. Dry gas</td>
<td>(no liquid)</td>
<td></td>
</tr>
<tr>
<td>2. Wet gas</td>
<td>1 bbl/100 MCF</td>
<td>50-70°</td>
</tr>
<tr>
<td>3. Condensate</td>
<td>5 to 100 MCF/bbl</td>
<td>50°-70°</td>
</tr>
<tr>
<td>4. Volatile oil</td>
<td>3000 CF/bbl</td>
<td>40°-50°</td>
</tr>
<tr>
<td>5. Black oil or dissolved gas systems</td>
<td>100-2500CF/bbl</td>
<td>30°-40°</td>
</tr>
<tr>
<td>6. Heavy oil</td>
<td>0</td>
<td>20°-25°</td>
</tr>
</tbody>
</table>

**Table 1: Classification and composition of reservoir hydrocarbons:**

**Depletion and Conservation**

The first or primary phase of oil production begins with the discovery of an oilfield using the natural stored energy to move the oil to the wells. When this energy is depleted, production declines and the second or secondary phase of oil production begins when supplemental energy is added to the reservoir by injection of water and/or gas. If the formation pressure is too low, and water or gas injection cannot maintain pressure or is not suitable, then the well must be artificially lifted. There are several techniques which are available to assist in bringing oil to surface and these are collectively referred to as Artificial Lift Techniques. These processes are widely applied in all geographical areas. In some cases, they are essential to the initial economic development of a hydrocarbon reservoir whilst in other cases they are implemented later in the life of the field to maintain production at economic levels. There are four major types of artificial lift techniques. These include gas lift, sucker rod pumping, submersible pumping and hydraulic pumping. When the net profit diminishes because the difference between the value of the produced oil and the cost of secondary production becomes too narrow, the tertiary period of production begins. Since this last period in the history of the field commences with the introduction of chemical and thermal energy to enhance the production of oil, it has been labelled as enhanced oil recovery (EOR).
(D) DRILLING

Drilling History

The first oil well was drilled in the United States in 1859 to a depth of 69½ feet, by the method of cable tool drilling. The well was drilled by Colonel Edwin Laurentine Drake and thus the well was called ‘Drake well’, located near Titusville in Pennsylvania. This was the beginning of the advancement of petroleum technology.

The ultimate purpose of drilling an oil or gas well is to provide a conduit, from the reservoir to the surface which will permit the commercial withdrawal of fluids from the reservoir. All wells drilled should yield geological information for purposes of reservoir control and evaluation and discovery of resources. Both oil and gas wells are being drilled on land, offshore, and in swamps or marshes. These wells can be classified as either Exploratory wells, Appraisal or Development wells. The presence of oil or gas is confirmed only after drilling through the formation. Exploratory well, therefore, is a well that is drilled primarily to confirm the existence of hydrocarbon (oil and gas) in a field. Wildcat well is the first exploratory well drilled in a particular field. Appraisal wells are wells drilled to determine the extent of the field usually drilled after a successful wildcat. Development wells are wells used to exploit a known extent of the field. Development wells can be infill (drilled between existing wells); a re-drill or re-entry (drilled from an existing wellbore) or step-out (drilled to determine the field’s boundaries).

There are basically three methods used in the art of drilling for oil and gas. These are Cable Tool Drilling method, the Rotary Drilling technique and recently the Top drive method (modern rotary method).

1. Cable Tool Drilling Method

This is a method of drilling a hole, whereby a heavy cutting tool (bit) is suspended on a cable and it is driven into the ground under its own weight, thus making a hole. The tool is brought out to the surface once in a while in order to remove the earth from it and to get it properly cleaned. No fluid is circulated in the hole.

Cable tools are often used for drilling through sensitive hydrocarbon formations which might be damaged by rotary drilling mud (even though rotary methods were used to drill down to the top of the formation). The drilling operations are intermittent in nature and tend to give slower rates of penetration than the rotary method. Although many cable tool-tool wells have been drilled to depths of 8, 000 feet or more, the best operating total depth limits are probably less than 2, 000 feet.
The general drilling procedure consists of drilling about five to eight feet of hole, withdrawing the drilling tools, then removing the drilled rock material from the hole and again proceeding with actual drilling.

This method however has been superseded by the more modern rotary drilling method.

The current applications of cable tool drilling include:

1. Remedial and cleanout work (post-completion work on wells).
2. Preparatory work for rotary drilling.
3. Water well drilling – shallow water wells used to supply rotary rigs are sometimes drilled with cable tool rigs.

2. Rotary Drilling Technique

Rotary drilling technique was first practiced by Leschot, a French civil engineer. Its early application was for water well drilling. The technique was introduced into the petroleum industry in 1901 at Spindletop, Texas by Captain Lucas. It was initially used for drilling wells which had to penetrate offshore sections that could not be drilled or prevented from caving by cable-tool methods.

Basic Operation

In the rotary drilling method, the hole is drilled by a rotating bit to which a downward force is applied. The bit is fastened to, and rotated by, a drill string, which is composed of drill pipes and drill collars, connected by joints. The cuttings are lifted from the hole by the drilling fluid which is continuously circulated through the bit nozzles, and upward in the annular space between the drill pipe and the bore hole. At the surface, the returning fluid is diverted through a series of tanks (solid removal equipment and mud pits) which afford a sufficient setting time to allow cuttings to separate and to allow any necessary treatment to the mud. The mud, after setting, is circulated up by the pump suction, and the circle is repeated.
3. Top Drive Systems

Modern rotary system is TOP DRIVE, also called power swivel. A top drive system replaces the functions of the rotary table and allows the drillstring to be rotated from the top, using the power swivel instead of a kelly and rotary table (i.e. in this system the regular swivel, kelly, and kelly bushing are entirely eliminated). The power swivel replaces the conventional rotary system, although a conventional rotary table would generally, also be available as a back-up.

Most offshore drilling rigs now have top drive systems installed in the derrick. The power swivel is remotely controlled from the driller’s console, and can be set back if necessary to allow conventional operations to be carried out.

The advantages of this system are:

- Has built-in tongs to make and breakout pipes.
- Uses a hydraulic motor to achieve rotation.
- Safer & easier for crew members to handle the drill pipe.
- It enables complete 90' stands of pipe to be added to the string rather than the conventional 30' singles. This saves rig time since 2 out of every 3 connections are eliminated. It also makes coring operations more efficient.

Although Top drive systems are now very widely used, it also has some disadvantages.

The disadvantages of a top drive system are:

- Increase in topside weight on the rig.
- Electric and hydraulic control lines must be run up inside the derrick.
Figure 4.3: Top drive systems

Figure 4.4: A driller’s console
Types of drilling rigs.

A rig includes the derrick, drawworks, rotary table and all associated equipment required to drill a well. There are three main types of rig:
- Land Rig (Onshore rig)
- Swamp Rig
- Offshore Rig

Figure 4.5: Rig types
Land rig.

Figure 4.6: A heavy land rig

Figure 4.7: A desert rig

Swamp Rig

A swamp rig is also called a barge rig. They are bottom-supported. They are not self-propelled but usually towed by boats.

Figure 4.8: Swamp barges
Offshore rigs.

They are of various types and include:

Jack- up rigs
Semi- submersible drilling rigs
Drill ship
Platforms

Jack – up rig:

They are fixed rig and often used in shallow offshore.

Figure 4.9: A jack- up rig

Figure 4.10: A semi- submersible rig

Semi- Submersible Rig & Drill ship

They are deep offshore rigs, could be floating, anchored or dynamically positioned. While semi- submersible rig is towed on to location, drill ship is self- propelled for rig moves.
**Platform rig**

A platform rig is an immobile offshore structure from which development wells are drilled and produced. Platform rigs may be built of concrete, steel or tension leg.
Rotary Drilling equipment

All rotary rigs have the same basic drilling equipment, with the following major components or systems (Figure 4.16)

1. Hoisting system
2. Rotary system
3. Fluid-circulating system
4. Well control system

The primary function of the drilling rig used in the oil industry is to drill a hole that penetrates an oil or gas reservoir in a safe and timely manner. Starting from the bottom of the hole, the drilling bit is the business end of the whole system as it is the only piece of equipment that actually makes hole. All of the rest of the equipment can be considered as the support system; to raise and lower the bit into the hole (Hoisting), to rotate the bit with controlled weight (Rotary); to flush the cuttings from the bit/rock interface as the hole is drilled (Circulating); and to provide fluid pressure control as the bit penetrates beds of rock that may contain gas, oil or water at high pressure (Control).

1. The Hoisting System

Function: To provide a means of lowering and raising equipment into or out of the hole.
Principal components
- Block-and tackle system (crown block & travelling block) [Provides a mechanical advantage, which permits easier handling of large loads]
- Draw works [The drawworks is the control center of the rig and it houses the drum which spools the drilling line]
- Derrick (mast) [support the crown block and all of the load carried by, and including, the travelling block and hook]
  Substructures [supports the derrick]
  Miscellaneous hoisting equipment (hooks, elevators, tongs and slips)

Major routine operations
- Making connection
- Making a trip (Running the successive strings of casing and production tubing in and out of the hole during drilling operation is called "tripping in" and "tripping out").

Figure 4.16a: Rotary drilling equipment
2. Rotary System  
**Function:** The rotary system is used to rotate the drill-string, and therefore the drill bit, on the bottom of the borehole.

**Principal components**
The rotary system includes all the equipment used to achieve bit rotation:
- Drill string (swivel, rotary Kelly, drill pipe, drill collar, rock bit)
- Rotary table/ top drive or power swivel.

3. Drill string
Drill String: The drill string is a column of drill pipes and drill collars with attached tool joints that transmit drilling fluid and rotational power from the Kelly to the bit. The drill string links the bit with the surface equipment (via the swivel) and it is made up of pipes screwed together, namely the Kelly, drill pipes and drill collar. The top length of the drill string, represented by the Kelly is coupled to the swivel through the upper Kelly cock, and the lower end of the Kelly is connected to the first drill pipe joint through the lower Kelly cock.
4. The circulating System

**Function** is to remove rock cuttings out of the hole as drilling progresses.

**Principal components**

- Mud pump [circulates fluid at desired pressures and flow rates].
- Return line [The fluid from the annulus returns via the return line to the solid control equipment where solids and gas bubbles are stripped off before the system returns to the suction tank or active pit].
- Solid control equipment [shale shaker (removes the large cuttings), desander (remove sand to prevent abrasion) desilter (removes very fine particles and silt) and degasser (removes entrained gas from the fluid)].
- Standpipe [The standpipe transfers mud from the mud pumps through the kelly hose to the drill string via swivel].
Drilling Fluids
Drilling fluids are generally the "blood" of all drilling operations and the petroleum industry especially has continued to make increasing use of these fluids. A drilling fluid, or mud, is any fluid that is used in a drilling operation in which that fluid is circulated or pumped from the surface, down the drill string, through the bit, and back to the surface via the annulus. The simplest drilling fluid is water, either fresh water or sea water, and it is commonly used to drill the shallow sections of the hole.

Functions of the drilling fluid/mud.
1. Control pressures of formations penetrated. This is achieved by ensuring that the hydrostatic column of drilling fluid exerts a pressure on the formation that is higher than the water, oil or gas pressure in the formation. This prevents entry of the formation fluids or gases into the wellbore. Hydrostatic pressure is the force exerted by a fluid column and depends on the mud density and true vertical depth (TVD).

\[ P_h = 0.052 \ (MW) \ (D) \]  

Where,
\( P_h \) = Hydrostatic Pressure (pounds per square inch (psi));  
0.052 = Conversion Constant; \( MW \) = Mud weight/ Density (lb/gal); \( D \) = Depth (True Vertical depth (TVD), feet).
2. Clear the cuttings from between the drilling bit and the cutting face on bottom. This is achieved by the large volume of drilling fluid blasting through the nozzles on the bit that is positioned to clear the freshly cut face. This jetting action also provides a hydraulic cutting action which can be significant in some rock formations.

3. Remove the cuttings from the hole. This is achieved by its carrying properties, directly related to its “gel strength”, and the upward velocity of the annulus return.

4. Cool and lubricate the drilling assembly. The cooling is achieved by providing a cooler drilling fluid from the suction pit and circulating out the hot drilling fluid generated downhole by the cutting action of the bit and the deeper, hotter formations. The drilling fluid provides lubrication by lessening the frictional losses between the drill string, the walls of the drilled hole, and at the cutting face between the bit and rock.

5. Consolidate the walls of the drilled hole to prevent the caving-in, or collapse, of certain types of rock into the wellbore. This is achieved by the drilling fluids capacity to deposit a thin "mud cake" on the walls of the hole. The mud cake forms because the hydrostatic pressure of the drilling fluid is greater than the formation pressure and a natural loss of drilling fluid to the formation occurs. Large losses of drilling fluid are prevented by the “mud cake” forming on the walls of the hole, just as a filter cake forms in any filtration process.

Blowout prevention and equipment

Blowout Preventers: A well is said to have a blow-out when formation fluid enter into the wellbore at pressures much higher than those exerted by the drilling mud. The result of this is a disaster which can be referred to as a ‘’kick’’ or in strong term, a ‘’blow out’’. In order to avoid blow-outs, all drilling rigs install what we call blow-out preventer. It is a safety equipment installed at the wellhead to permit the control of escaped pressure in the hole.

Figure 4.19: Blowout in a platform
Figure 4.20: Blowout preventers

Casing and cementing

Casing:
Generally, it is not possible to drill most oil/gas wells through all the formations from (surface or the seabed) to the target depth in one hole section. The well is therefore drilled in sections, with each section being sealed off by lining the inside of the borehole with steel pipe, known as casing and filling the annular space between this casing string and the borehole with cement, before drilling the subsequent hole.

Why casing:
- To contain pressures
- To prevent hole collapse
- To prevent contamination of fresh water zones
- To provide a means of controlling fluid influxes
- To provide a container for drilling fluids.
- To confine produced hydrocarbons to the well-bore.
- To provide a means of anchoring the BOPs & Xmas tree.
Cementing

Oil/gas well cementing operation is the process of mixing and displacing a cement slurry down the casing and up the annular space behind the casing where it is allowed to set, thus bonding the casing to the formation. No other operation in the drilling and completion process plays as important a role in the producing life of a well as does a successful primary cementing job.
Main objective: to cement casing string so as to facilitate zonal isolation necessary to drill further or control production; cement will prevent corrosion of the casing

Directional drilling

Directional Drilling is the process of directing a wellbore along some trajectory to a predetermined target. Basically it refers to drilling in a non-vertical direction.

Applications of directional drilling

Fig. 4.24: Typical offshore development platform with directional wells
**Fig 4.25:** Developing a field under a city using directionally drilled wells

**Fig 4.26:** Drilling of directional wells where the reservoir is beneath a major surface obstruction

**Fig 4.27:** Using an old well to explore for new oil by sidetracking out of the casing and drilling directionally