



**SUMMER TRAINING REPORT ON PETROPHYSICAL STUDIES
AND PHASE BEHAVIOR STUDIES OF CORE SAMPLES**



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B.Tech III Year

Chemical Engineering

Vellore Institute of Technology, Vellore

(December 8 to January 1)



**PETROPHYSICAL STUDIES LABORATORY
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CERTIFICATE

This is to certify that **Kritika Kashyap**, student of B.Tech Chemical Engineering (III Year) Vellore Institute of Technology, Vellore has successfully completed her summer training on “**Petrophysical studies and Phase Behavior studies of core samples**” at Dr. B.R. Ambedkar Regional Geoscience Laboratories, ONGC, Vadodara during 8th December 2015 to January 1st 2016.

Leena John
Chief Chemist

Atanu Banerjee
GM-Head RGL

PREFACE

As a part of B.Tech Chemical Engineering (III Year) and in order to gain practical knowledge in the field of exploration and production, I required to undergo industrial training. Thus ONGC has given me an opportunity to work as an intern at D.r. B.R. Ambedkar Regional Geoscience Laboratory in Petrophysical and Phase Behavior Lab. This training program proved to be highly informative and it has enhanced my knowledge about the analysis of core analysis in the field of exploration.

Various studies on core samples are held for the determination of following parameters :

- Effective Porosity
- Air Permeability
- Grain and Bulk Density
- Gas-Oil Ratio
- Formation Volume Factor
- Density
- Viscosity
- Composition
- Phase Behavior
- Type of Oil
- Bubble Point
- Dew Point

The primary objective of these experiments is to determine the quality and quantity of oil of a particular site, the type of equipment that will be required to extract it and the conditions at which the extraction must be held. It also helps us to predict the total hydrocarbon content of the site.

ACKNOWLEDGEMENT

I would like to express my sincere thanks and gratefulness to Mr. Atanu Banerjee, GM-Head RGL, ONGC for providing excellent facilities and constant inspiration during my project work.

I am also grateful to Mr. B K Shukla, DGM-Head Chemistry for his valuable suggestions and guidance.

I would like to thank my Project Guide and mentor Mrs. Leena John, Chief Chemist for her critical evaluation, guidance and encouragement during the course of my project.

I also extend my sincere thanks to Mrs. Dipika Solanki, Chemist and Mr. Amit Patel, JTA, for extending support and providing me knowledgeable information for my work.

This internship program gave me an insight of a real working atmosphere. I am thankful for the co-operation received during the period of my industrial training.

I am also thankful to my parents and relatives who have been a constant source of motivational and boundless benediction.

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1.0 CORPORATE PROFILE

ONGC is a national oil company of India engaged in exploration and production of oil and gas. It is a public sector undertaking (PSU) of government of India, under the administrative control of Ministry of Petroleum and Natural Gas. ONGC was founded on 14th August 1956 by Government of India, which currently holds a 69.23% equity stake. It is involved in exploring for and exploiting hydrocarbons in 236 sedimentary basins of India, and owns and operates over 11,000 Kilometers of pipelines in the country. Its international subsidiary ONGC Videsh currently has projects in 15 countries. ONGC is engaged primarily in the exploration, development and production of crude oil and natural gas in India, both offshore and onshore. The company's major products include crude oil, natural gas, LPG, naphtha, SKO and HSD. The company is also involved in other activities such as deep water exploration and drilling, exploration in frontier basins, marginal field development plan, field recovery and other allied areas of service sector.

1.2 MAJOR ACHIEVEMENTS OF ONGC

- Judged as Asia's best Oil and Gas Company, as per a recent survey concluded by US bases magazine 'Global Finance'.
- Ranked as the second biggest E&P Company as per the Platts Energy Business Technology (EBT) Survey 2004.
- Leads the list of Indian companies listed in Forbes 400 Global Corporates and Financial Times Global 500 by Market Capitalization.
- Only fully integrated Petroleum Company in India, operating along the entire hydrocarbon value chain.
- Holds largest share of hydrocarbon acreages in India.

2.0 PETROPHYSICAL STUDIES – “AN OVERVIEW”

The objective of exploration phase is to locate hydrocarbon-bearing structure, which will produce oil and gas in sufficient quantity. In order to locate oil and hydrocarbon bearing structure it is important to estimate the property of reservoir rock which are necessary concerning the lithology and petrophysical studies.

2.1 Steps of Petrophysical Analysis :

- Core Sampling
- Core Cutting
- Numbering of core sample
- Extraction
- Drying and Dressing

2.1.1 Core Sampling

Core is a small section of the rock samples removed from a petroleum reservoir for the estimation of reservoir rock properties. Cores are transported from field to the lab for core analysis. Sandstones are normally considered as sample. Clay and shale are not considered as samples.

2.1.2 Sample Cutting

Core is taken and cut into the size of own interest using a core cutting machine. The core is cut in cylindrical shapes. Cores are cut horizontally from centre of the core. Samples of 1 inch in diameter and 4 inch in length are cut from every foot of productive zone.

2.1.3 Numbering of Core Samples

After cutting, the samples (core plugs) are assigned a laboratory serial number (LSN).

2.1.4 Extraction

Prior to most laboratory measurements of porosity and permeability, the original fluids must be completely removed from the core sample. A soxhlet extractor is used to extract oil

and brine from the sample. Core plug is taken and soxhlet extracted using toluene as solvent for about 72 hours to remove hydrocarbons present in it. Then core plugs are extracted with acetone and methanol (50:50) solution for about 72 hours to extract brine.

2.1.5 Drying and Dressing

All core plugs after extraction, they are dried in an oven for 6-8 hours at 40-60 degree Celcius. After drying, the plugs are properly dressed, numbered and then taken to the lab for studies like effective porosity, permeability etc.

3.0 POROSITY

The petroleum reservoir rocks are a sandstone sample that appear to be solid but are often not solid. These rocks are an accumulation of varying sand grains with open spaces remaining between the grains. Petroleum reservoir fluids are stored in these pores. The storage capacity of these reservoir rocks is called porosity. The specific definition of porosity is the ratio of pore volume(void volume) in a reservoir rock to the total volume(bulk volume) and is expressed in percentage.

$$\text{Porosity} = \frac{\text{Pore Volume}}{\text{Total Volume}} = \Phi .$$

3.1 Types of Porosities

Every porous medium or reservoir rock has three different types of pores :

- Interconnected Pores
- Dead-End Pores
- Isolated Pores

3.1.1 Total/Absolute Porosity

It is defined by the ratio of total void space in the reservoir rock to the total volume of rock.

3.1.2 Effective Porosity

It is defined by the ratio of the volume of interconnected and dead end pores to the total volume.

3.1.3 Ineffective Porosity

It is defined by the ratio of volume of isolated or disconnected pores to the total volume.

3.2 Classification of Porosity

They are classified by the mode of origin as either original or induced which can also be referred to as primary or secondary porosity. Original porosity is developed in the deposition of material. Induced porosity is developed by some geological process following the deposition of the rock.

3.3 Parameters That Influence Porosity

- Grain Size
- Grain Shape
- Sorting
- Clay Content
- Compaction
- Cementation

3.4 Laboratory Measurement of Porosity

- Routine Core Analysis
- Well Clogging Techniques : This technique is indirect in nature and generally the porosity is measured *in situ* i.e. in the vicinity of the wellbore.
- X-Ray Computerised Tomography

3.4.1 General Insight

A given reservoir rock sample comprises three different volumes : Bulk Volume(BV), Pore Volume(PV), Grain Volume(GV) which follow the following relation-

$$BV = PV + GV$$

3.4.2 Bulk Volume Measurement

- Cylindrical core plugs are used and their BV can be calculated by the relation $BV = (\pi/4)D^2L$ where L=length and D=diameter.
- But inaccuracies might occur in case of chipped samples and slight geometrical irregularities.
- To avoid such irregularities another method can be employed in which the volume of fluid displaced by the sample (Archimedes Principle) is observed gravimetrically.
- This method is useful for irregular and well defined samples alike.
- It is important to prevent the penetration of fluid used in observing displacement into the pore space since this affects BV calculation.
- The sample can be coated with paraffin wax or mercury can be used as a fluid which does not enter the pore space unless forced or the sample can be pre saturated with the same fluid used for observing displacement.
- Correction factors will be needed in case of coating of sample.
- Pre-saturating with the fluid is advantageous because this gives us the measure of both BV and PV.
- a=weight of dry sample in air
b=weight of mercury filled pycnometer
c=weight of mercury filled pycnometer containing the sample
ρ=density of mercury
 $BV = a + b - c/\rho$

3.4.3 Pore Volume Measurement

- Extraction Method : Suitable solvents are used to recover the fluids in the pore space. The total volume of fluid extracted gives the measure of PV.
- Reintroduction of Fluid : The different fluids used for this are-helium, water, synthetic oil or mercury. The volume of fluid entered gives the measure of effective porosity.

3.4.4 Helium Porosimeter

- Helium is a clean inert gas which does not cause unwanted rock-fluid interaction.
- It is less time consuming.
- Principle of Boyls's Law is employed where $PV=\text{constant}$
- The apparatus consists of two equal volume chambers called reference chamber and sample chamber.
- The reference chamber is at a pressure P_1 and volume V_1 and the sample chamber is at pressure P_2 and unknown volume V_2 .
- The system is then brought to equilibrium and equilibrium pressure is noted which helps in finding the unknown volume by the following relation
$$P_1V_1+P_2V_2=P(V_1+V_2)$$
- $V_2=V_1-BV+PV$
- Porosity= V_2-V_1+BV/BV

3.4.4.1 Steps Involved in Operating He Porosimeter

- Open the APPLILAB software.
- Perform the calibration operation in order to ensure the errors associate with the apparatus.
- Then first take the check plug (numbered) and put it into the matrix and fill up matrix

with proper Billets and tick their respective No. in the Applilab dialogue box.

- Then give details in Applilab dialogue box on the right side i.e. Operator Name, Sample Name, Weight, Diameter and Length (using vernier callipers) of the given check plug which we have to measure.
- Click on Start. Open windows check parameters. Yes to proceed and No to stop.
- Click on Yes.
- Switch right valve to vent.
- Click on OK.
- Switch left valve to ON.
- Click on OK.
- Switch left valve to OFF.
- Click on OK.
- HeP measure wait for Pref Stability.
- Switch right valve to EXPAND.
- HeP measure wait for P_{exp} stability.
- Switch right valve to vent.
- Then the apparatus automatically determines the core porosity and grain density.

3.4.5 Vacuum Saturation

- Advantage of this method is that multiple samples can be tested together.
- The method uses a large vacuum flask or a beaker filled with a degassed liquid (generally water) in which dry rock samples are placed.

- As soon as the evacuation of vacuum flask is initiated, air bubbles are seen in the saturating liquid as it replaces air from the pore space of the rock sample.
- The disappearance of air bubbles gives the indication that the saturation is complete and hence evacuation is terminated and porosity is calculated as

$$\text{Porosity} = (WW - DW) / BV * \rho$$

where WW=weight of wet sample

DW=weight of dry sample

ρ =density of saturating liquid

3.4.6 Grain Volume Measurement :

- Methods for measuring grain volume usually involve crushing the rock and calculating the grain volume.
- The Helium Porosimeter can also be used for this method too.
- $V_2 = V_1 - GV$

3.4.7 Non Conventional Method of Porosity Measurements

- This is based on the x-ray computerized tomography.
- The basic principle involves imaging of the core plug sample when it is clean and dry and then when it is saturated with either oil or liquid.
- The image of the clean sample is subtracted from the saturated sample to obtain porosity.

3.4.8 Averaging of Porosity

The porosity that we determine is for small core plugs. Therefore porosity must be averaged and scaled up from core scale to reservoir scale.

Different Averaging Methods are:

- Arithmetic Average
- Thickness-weighted Average
- Area-weighted Average
- Volume-weighted Averages

4.0 PERMEABILITY

Permeability is a property of the porous medium that measures the capacity and ability of the formation to transmit fluids. The rock permeability, k , is a very important rock property because it controls the directional movement and the flow rate of reservoir fluids in the formation. This rock characterization was first defined mathematically by Henry Darcy in 1856. In fact, the equation that defines permeability in terms of measureable quantities is called **Darcy's Law**. Permeability is a property of the rock alone and not the fluid that flows through it.

Mathematical expression for calculating permeability of a porous medium is given by

$$Q = KA(h_1 - h_2)/L$$

Q is the volumetric flow rate through the core plug

K is the proportionality constant or the hydraulic conductivity

A is the cross sectional area of the core plug

L is the length of the core plug

h_1 and h_2 are the hydraulic heads at inlet and outlet

$$Q = -kA \frac{dP}{dL} \frac{1}{\mu}$$

dP is the difference between the upstream and downstream pressures

k is the permeability of the porous medium

μ is the fluid viscosity

4.0.1 Permeability has the units ft^2 . But this is too large a measure for a porous medium. Hence the unit “darcy” is adopted for permeability. A porous medium is said to have a permeability of one darcy when a single-phase fluid having a viscosity of one centipoise completely saturates the porous medium and flows through it at a rate of 1cc/s under a viscous flow regime and a pressure gradient of 1atm/s through a cross sectional area of 1cm^2 .

$$1\text{D} = 1000\text{mD}$$

- 4.0.2 In case of an inclined flow or a dipping flow, the vertical coordinate or the gradient should also be accounted for by calculating the absolute permeability.

$$Q = kA/\mu[(P_1-P_2)/L - \ell g \sin \alpha]$$

ℓ is the fluid density

g is the acceleration due to gravity

α is the angle of inclination or dip

- 4.0.3 The flow of reservoir fluids from a cylindrical drainage zone into a well bore is characterized by the radial flow system.(add img pg43)

$$Q = 2\pi kh(P_e - P_{wf})/\mu \ln(r_e/r_w)$$

h is the thickness of the well bore

P_e is the pressure at drainage radius

P_{wf} is the flowing pressure

r_e is the drainage radius

r_w is the well-bore radius

- 4.0.4 Reservoir rocks are often not uniform and consistent and may contain distinct layers, blocks, or concentric rings of fixed permeability. Hence permeability values are averaged according to the type of flow : series or parallel.

4.0.5 Parallel Flow

- When the height of each section varies

$$Q_t = k_{avg} W h_t \Delta P / \mu L$$

where $k_{avg} = \sum k_i h_i / \sum h_i$

- When width of the layers is varied

$$Q_t = k_{avg} (\sum W_i h_i) \Delta P / \mu L$$

where $k_{avg} = \sum k_i W_i h_i / \sum W_i h_i$

4.0.6 Series Flow :

- Darcy's law can be written for the total flow rate as :

$$Q_t = k_{avg} W H \Delta P / \mu L$$

where $k_{avg} = \sum L_i / \sum (L_i / k_i)$

4.1 Measurement of Absolute Permeability Using Liquids

- The most common liquids used for the measurement of absolute permeability are formation waters (brine), degassed crude oil and synthetic oil such as ISOPAR-L.
- The dimensions of the core plug are recorded.
- The core plug is fit in a Viton sleeve and mounted on a case holder.
- A confining pressure is applied radially to the core held in Viton sleeve via a hydraulic pump.
- A constant reservoir temperature is maintained.
- A displacement pump and floating piston sample cylinder is used in combination to initiate the flow of brine or degassed crude oil at either constant rate or constant differential pressure.
- The pressure drop across the core plug is monitored using a computerized data logging system.
- The viscosity of brine or oil is measured at flooding pressure and temperature conditions.
- The absolute permeability is determined using Darcy equation.

4.2 Measurement of Absolute Permeability Using Gases

- Dry gases such as nitrogen, helium or air are commonly used as fluid medium in permeability measurements.
- The experimental procedures for permeability measurement using liquid and gases are basically similar, one major difference being the compressible nature of gases.
- Darcy equation was developed under the assumption of an incompressible fluid flow.
- Therefore the modified form of Darcy equation is

$$Q = kA(P_1^2 - P_2^2) / 2\mu L P_2$$

Q is the gas flow rate measured at the outlet of the sample

K is the absolute permeability

A is the cross sectional area

P₁ is the inlet pressure

P₂ is the outlet pressure

μ is the gas viscosity

L is the length of sample

- But there are variations in absolute permeability as determined using gases from those obtained when using non-reactive fluids.
- Permeability is different when different gases like hydrogen, helium, nitrogen, CO_2 are used. This is due to **gas slippage** or **Klikenberg effect** when the diameter of the capillary openings approach the mean free path of the gas.
- A straight line is obtained when gas permeabilities are plotted against reciprocal mean pressure.
- The lowest molecular weight gas (hydrogen) has the highest slope due to higher slippage.
- These straight lines for all gases when extrapolated to zero reciprocal mean pressure intersect permeability axis at the same point which is equal to the liquid permeability because gases tend to behave like liquids at high temperature.
- Mathematically this can be represented as

$$k_{\text{gas}} = k_{\text{liquid}} + m(1/P_{\text{mean}})$$

k_{gas} is the measured gas permeability

k_{liquid} is the equivalent liquid permeability

$$P_{\text{mean}} = (P_1 + P_2)/2$$

4.3 Steps for Using Air Permeameter

- Connect to main supply and power up the instrument at main switch on the panel. The transducers require a warm up period of about half an hour before use. During process, about 10 seconds are necessary to allow reading to arise from '0' the actual measurement.
- Switch the source valve ON/OFF to OFF option.
- All regulators are turned anticlockwise initially.
- Connect two regulated nitrogen supply to appropriate ports on rear of the onstruments, i.e. confining pressure supply at valve PRESSURE/VENT(1/8" OD) and nitrogen supply at valve ON/OFF(1/4" OD). Make sure to use tubing stand safely.

- Load the core holders that are available for samples of 1", 0.5" and 30mm.
- Regulate confining pressure nitrogen supply to desired value registered on supply cylindrical gauge. Regulate core nitrogen supply using cylindrical regulator to just above desired maximum test pressure.
- Turn confining valve PRESSURE/VENT to pressure. Nitrogen at desired pressure (400 psig) is now displayed on confining pressure gauge.
- Also connected with PC APPLILAB SOFTWARE installed which gives instruction to operate the instrument.
- All regulators are turned anticlockwise initially.
- We will start the instrument (APPLILAB SOFTWARE) half an hour before measurement.
- Click on APPLILAB icon and enter the required data.
- Now load the sample into the sample holder.
- Turn the knob towards ON and pressure.
- Turn the knob towards forward flow.
- By turning the regulator clockwise give the pressure to sample, measure flow in flow meter.
- Check the differential pressure by turning knob towards DP ON.
- If pressure is higher than 8psi then take only single reading, and dp between 0-8 then turn towards backward flow and take three readings.
- Klinkenberg permeability will be automatically calculated in XL sheet.

4.4 Factors Affecting Absolute Permeability :

- Rock related factors are basic characteristics, structure, or indigenous properties of reservoir rocks, such as grain size and shape and clay cementing. These are termed as natural factors.

- The type of fluid medium (i.e. gas/brine/water) used for permeability measurements as well as physical and chemical characteristics of these fluids are also major factors that affect absolute permeability. These factors are called artificial or laboratory factors which might temporarily affect permeability.
- The thermodynamic factors affecting absolute permeability basically consist of temperature effects and fall under the category of fluid-rock interaction-induced laboratory artifacts.
- Mechanical factors are related to the effect of mechanical stresses or confining pressures on absolute permeability and fall under the category of laboratory artifacts.

5.0 INTRODUCTION TO PHASE BEHAVIOR

Petroleum reservoir fluids may exist solely in gas phase, liquid phase, equilibrated gas-liquid phases, or in some rare cases as a solid phase, depending upon the prevalent pressure and temperature conditions in the substrate formations.

Petroleum reservoir fluids are generally complex mixtures of a number of hydrocarbons (paraffins, naphthalenes, and aromatics) and even some non-hydrocarbon components. The domain in which petroleum reservoir fluids behave in a certain fashion is defined by pressure, temperature, chemistry and composition.

During the producing life of a particular petroleum reservoir, most of these variables continuously change resulting in variations in the state of their existence, the amount in which they are present and their physical properties. All this is broadly characterized as **phase behaviour**.

5.2 Phase Rule

$$F = C - P + 2$$

F is the degrees of freedom

C is the number of components

P is the number of phases

At triple point when ice, liquid and water vapour coexist in a single

component, the value of F is 0.

5.3 Phase Diagram

A pressure-temperature plot that describes the conditions under which various phases of a component are present.

5.4 Vapor Pressure Curve

The vapour pressure curve joined by triple point (TP) and critical point (CP) separates the pressure-temperature (PT) conditions at which the component is a liquid from the conditions at which it is a gas.[graph]

5.5 Bubble Point

Under isothermal conditions of expansion of liquid or temperature increase, the occurrence of a small gas bubble gives bubble point pressure.

5.6 Dew Point

Under isothermal conditions of compression of gas or temperature decrease, the occurrence of a small drop of liquid gives the dew point pressure. For a pure component, the bubble point and dew point pressures are equal to the vapour pressure at a given temperature of interest.

5.7 Critical Point

The end point or the upper limit of the VP curve is called the critical point. It represents the maximum pressure and temperature at which a pure component can form coexisting phases (pure sample only).

5.8 Triple Point

The temperature and pressure conditions at which all three phases of a component coexist under equilibrium.

5.9 Partially Supercritical

Demonstrates liquid like behaviour if conditions exist where only the pressure is greater than the critical pressure, while temperature is less than its critical temperature. Demonstrates vapour like behaviour when only temperature is greater than critical temperature and pressure is less than critical pressure.

5.10 Pressure Volume diagram

At temperatures much less than critical temperature, there is a wide separation between the bubble point and the dew point curves which begins to narrow as the temperature approach the critical temperature.

5.11 Determination of Vapour Pressure

A simple laboratory measurement setup includes a PVT cell made of suitable material like stainless steel or titanium that has a mechanism for reducing or increasing cell volume (i.e. pressure) and a climatic air bath in which a constant test temperature can be achieved. Such a PVT cell normally has a small window through which visual information about the change of phase can be obtained. The entire vapour pressure curve can be constructed by varying the pressure by mercury injection/withdrawal or via a mechanically driven piston and observing the phase behaviour at different isotherms.

5.12 Phase Behaviour of Binary Systems

For a binary system to exist in a single phase pressure, temperature and composition/concentration needs to be specified. For existence of binary two phase system, two degrees of freedom are required which are pressure and temperature.

5.13 Phase Diagram of a Binary System

For a pure component, a single vapour pressure curve represents the two phase vapour-liquid equilibrium whereas for a binary system there is a broad region in which the two phases exist in equilibrium. This broad region is referred to as the phase envelope, saturation envelope or two-phase region. (pg-295)

5.14 Critical Point

Vapour and liquid can co-exist in equilibrium at pressures and temperatures even beyond the critical point. In other words, the phase envelope extends beyond the critical point. At points on Left Hand side of the critical point the binary mixture is in a single phase liquid like or more dense fluid. At points on the Right Hand side of the critical point the system is in a single phase vapour like or a less dense fluid. As the system moves farther away from critical conditions the transition from single phase vapour to single phase liquid or vice versa is relatively smooth and without any abrupt changes.

5.15 Bubble Point and Dew Point

Pressure depletion (isothermal expansion) occurs and liquid expands until the pressure reaches a point that meets the phase envelope or the boundary of the two phase region where a small amount of vapour is formed. This point is called bubble point denoted by P_b . As pressure depletion continues below bubble point pressure, the system passes through the two phase region and additional gas appears. Finally pressure depletion meets the other boundary of the two phase region where a small amount of liquid remains. This point is called the dew point denoted by P_d . Similar observations can be made at isobaric conditions where we will obtain a horizontal line cutting the phase envelope. But from reservoir operations standpoint and considering the fact that reservoir temperatures remain constant and only pressure is reduced, bubble-point and dew-point pressures are of more significance than bubble-point and dew-point temperatures.

5.16 Cricondenbar

Highest pressure on the phase envelope.

5.17 Cricondentherm

Highest temperature on the phase envelope.

5.18 Retrograde Dew Point and Condensation

If the expansion is carried out on the right hand side of the critical point, as pressure is decreased, the dew point curve is encountered and a small drop of liquid appears, primarily composed of the heaviest component in the system. This is exactly reverse of the behaviour expected, hence called retrograde or upper dew point pressure. As pressure decline continues, pressures fall within

the two phase region and more liquid appears. The pressure that occurs during this pressure decline is termed **retrograde condensate**. Eventually the retrograde liquid begins to re-vapourise as pressure falls to even lower values re-intersecting the dew point curve where a small amount of liquid remains, resulting in **lower dew point pressure**.

6.0 PHASE BEHAVIOR OF PETROLEUM RESERVOIR FLUIDS

Phase envelopes of petroleum reservoir fluids are primarily determined by the types and quantities or by the chemistry and the overall composition of a particular mixture. As the quantity of methane in the mixture decreases, the phase envelope slants towards the right, indicating that the two-phase region exists at relatively higher temperatures on the P-T diagram. Therefore, the phase envelope of the mixture having the highest methane composition is located at lower temperatures, while phase envelope having highest composition of n-butane exists at much higher temperatures.(fig 11.11)As the methane composition increases, the critical point trends towards the critical point of pure methane. Reservoir gases have relatively small phase envelopes and reservoir oils have relatively large phase envelopes. For reservoir gases methane is the most dominant component while reservoir oils consist of a wide range of intermediates and large molecules.

6.1 Plus Fraction

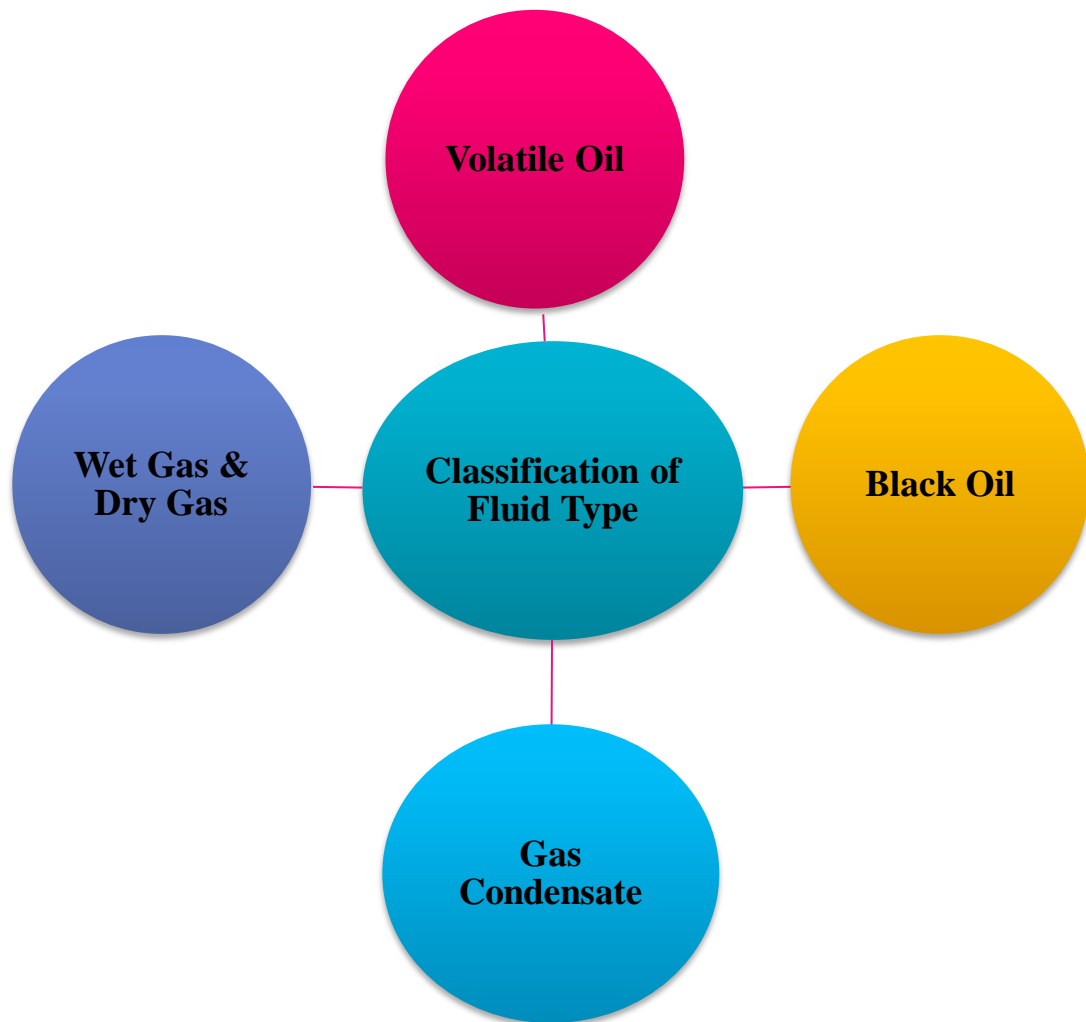
The lighter intermediate component of a petroleum reservoir fluid can be easily identified (methane, ethane through hexane), whereas the heavy unidentified components are grouped as a plus fraction. The plus fraction is extended to a carbon number of 20 or 30 (eg : C₂₀₊ or C₃₀₊). Their reservoir properties like specific gravity and molecular weight vary from one reservoir fluid to the other and are thus unique. The discretely identifies well defined components have the same properties regardless of the reservoir fluid they are present in.

6.2 Classification of Fluid Type

This helps in making decisions concerning field development plans and or reservoir management. Various issues such as fluid sampling, design of surface facilities, prediction of hydrocarbon reserves, strategy for production and enhanced oil recovery (EOR) are all dependant on the type of reservoir fluid.

6.3 Identification of Fluid Type

This can only be confirmed using laboratory analysis primarily including phase behaviour of reservoir fluids. This can be achieved based on the location of the point representing the initial reservoir pressure and temperature with respect to the phase envelope of a given fluid. Also production information like initial producing gas-to-oil ratio (GOR), gravity, and colour of stock tank oil, help indicate the oil type.



6.4 Black Oil

- Also referred to as **ordinary oils**.
- Composed of more than 20% of C7+, indicating a large quantity of heavy hydrocarbon product.
- Hence they have a wide phase envelope.
- It has a high critical temperature.
- The curves within the phase envelope are called the iso-vols or quality lines which represent the constant liquid volume. (fig 12.1)
- The separator conditions are within the phase envelope in the two-phase region, lying on relatively high-quality lines and indicating that a large amount of liquid arrives on the surface.
- The oil undergoes relatively less shrinkage when pressure as well as temperature reduction undertakes a curved path towards the separator, as the oil is produced. Therefore black oils are also called **low-shrinkage oil**.
- Initially, the GORs remain constant when reservoir pressures are above the bubble-point pressure. GORs may decrease initially when reservoir pressure falls below the bubble points because evolved gas remains immobile at very low saturations. As gas saturation exceeds critical gas saturation, gas also begins to flow, thus resulting in increase in GORs.
- The stock tank liquid is very dark, often black in color with a greenish cast or brown. It can be treated as a simple two component system consisting of gas (dominated by methane) and oil (dominated by C7).

6.5 Volatile Oil

- It is composed of 35+% methane through hexanes, 12.5-20% C7+, and the remainder being ethane.
- But the fraction of C7+ present here is relatively lesser than that in black oil and hence this has a smaller phase envelope with a lower cricondentherm.
- Pressure range covered by the phase envelope in volatile oils is relatively higher as compared to black oils.
- Volatile oils experience high shrinkage below bubble point.
- In volatile oils the produced gas phase is very rich and tends to behave like a retrograde gas thus contributing toward both the quantity and the quality of the stock tank liquid.
- The colour of stock tank liquids may be green, orange or brown.

6.6 Gas Condensate

- Also known as retrograde gases because the phase behaviour of these types of reservoir fluids is characterized by retrograde dew point and retrograde condensation.
- Their composition consists of methane (75%-85%), C7+ less than 12.5% and other intermediates which result in smaller phase envelope as compared to volatile oils with critical point moving further down the slope on the left hand side of the phase envelope.
- The phase behaviour of the gas-condensate fluids is sensitive to the concentration of C7+ fraction, practically controlling the retrograde dew point and the subsequent condensation and its characteristics.
- Its reservoir temperature lies between its critical temperature and the cricondenthem.
- An isothermal pressure reduction path, on the right hand side of the critical point and less than the cricondenthem, can also be considered for a gas-condensate fluid. The gas condensate is initially at single phase vapour. As reservoir pressure decreases, the expanding fluid exhibits a retrograde dew point. As pressure declines, liquid condenses from the gas due to retrograde condensation to form a free liquid or condensate in the reservoir.
- A recombination of the produced gas and the condensate at the surface represents the reservoir gas but not the total reservoir fluid because retrograde liquid is precipitated in the reservoir.
- Special chemicals can be used for treatment of liquid (condensate & water) blocking that shows great potential to increase production from gas-condensate wells.
- In bubble-point systems, the decline in pressure below bubble point simply causes reduction in the percentage of liquid. But in gas-condensate fluids (fig 12.3) the path BC initially crosses a quality line of low liquid percentage at pressures just below the dew point. As additional liquid appears due to retrograde condensation, quality lines of higher liquid percentage are now crossed. A further reduction in pressure results in line BC crossing the same iso-vol for the second time, where the condensate begins to revapourise. This is a very common feature of gas-condensate fluids.

- The liquid dropout reaches a maximum value followed by decrease due to revaporisation during pressure depletion. This implies that the condensate will be recoverable if pressure reduces sufficiently. But by the time the pressure falls below the dew point, the original phase envelope is no longer valid since the overall composition of the system changes during the production period. This makes it difficult to determine to what extent the pressure needs to be reduced. Danesh states that the condensation and loss of valuable components could be avoided by maintaining the reservoir pressure above the dew point by partial gas recycling, after removing the intermediate and heavy components of the produced fluid on the surface.
- High gravity condensates have lighter colours or are water white while those having low gravity have darker colour.
- Gas Condensate Ratios (GCRs) that are very high indicate that the phase envelope is very small, having cricondenthem close to the reservoir temperature and resulting in the precipitation of very little retrograde liquid. Such reservoir fluids are called **lean gas condensates**. In fact when GCR is above 50,000scf/STB, the reservoir fluid can be treated as wet gas.
- When GCR is low, large liquid dropouts are produced immediately below the dew point and are usually called **rich gas condensates**.

6.7 Wet Gases

- Primarily contains methane and some intermediates, and C7+ might be present in small amounts (1%).
- Has a small phase envelope. Hence the phase envelope is located entirely over a temperature range below that of the reservoir. Thus, the reservoir temperature is greater than the cricondenthem.
- It exists solely as a gas in the reservoir and does not drop out any condensate in the pore spaces, throughout the reduction in the reservoir pressure during depletion.
- However there is production of a little condensate, hence the name wet gas, the word wet signify the liquid hydrocarbons and has no relevance to water.
- It has water white colour.

6.8 Dry Gases

- Here the phase envelope shrinks even further in comparison to wet gases and generally occurs at even lower temperatures, with reservoir temperatures significantly higher than the cricondentherm.
- The gas is primarily composed of methane and a very small fraction of some intermediates and is thus incapable of producing condensate even at the surface due to lack of heavy molecules.
- Therefore dry gas remains single phase from reservoir to surface conditions and hence has the same composition throughout the producing life.

6.9 Saturated Hydrocarbon Reservoir

- In a saturated hydrocarbon reservoir consisting of a gas cap and an oil column, two separate phase envelope exist.
- If the phase envelope of the fluid from the gas cap and fluid from the oil column are plotted together, they would intersect at a point which would indicate reservoir temperature and pressure at the gas-oil contact.
- If both phases were to exist in equilibrium, then the dew point pressure of the gas in the gas cap and the bubble point pressure of the oil in the oil column at reservoir temperature will be equal to the reservoir pressure.

7.0 SAMPLING OF PETROLEUM RESERVOIR FLUIDS

The process of obtaining a physical reservoir fluid sample from a given formation is called sampling. Given the fact that sampling is an expensive operation and the need for fast track field development, sampling can perhaps take place only once, and there may not be a second opportunity of sampling if errors were made in the first instance. Reservoir fluid should be sampled as early as possible in the producing life of a reservoir because the most representative in situ samples are usually obtained when the reservoir fluid is single phase at the point of sampling.

7.1 Well Conditioning

- The process of producing the reservoir at low pressure drawdown, or low rates is known as well conditioning.
- It is an integral preceding step in sample collection in order to ensure that representative fluids are flowing out of the formation.
- This step is necessary to eliminate or minimize the two phase flow effects of wellbore.
- Following the period of reduced flow, the well is shut in for a certain period that is dependent on the productivity of the well (ranging from 2-3 hours to 72 hours).
- If the well bottomhole pressure has fallen below the bubble point, this lowering of pressure drawdown raises the oil pressure above its original bubble point.
- In case of saturated oil reservoirs, the low pressure drawdown also raises the oil pressure, possibly approaching saturation pressure which is equal to the reservoir pressure.
- But this repressurization method by lowering the drawdown might not be suitable for gas condensates if the reservoir pressure is below the dew point pressure as the pressure buildup may vaporize the retrograde condensate into the gas phase forming an even rich gas condensate. This will result in the collected sample being non-representative.
- In this case maintaining pressure above the dew-point pressure can ensure the flow of single phase gas into the wellbore.

7.2 Subsurface Sampling

- Reservoir fluid samples collected down hole or *in situ* are called subsurface or bottom hole samples.
- These samplers are designed to draw in a representative sample of the reservoir fluid at the base of the wellbore, adjacent to the perforations.
- The essential element of these samplers is a floating piston-type device that is also equipped with a pressure compensation mechanism, such as a nitrogen gas charge.
- The gas charge maintains pressure on the collected sample well above reservoir pressure so that it remains in single phase because pressure drops due to reduction in temperature on its trip to the surface.

- The sampler is usually lowered into the well to be sampled on wire line device.
- Typical bottom hole samplers are capable of handling pressures upto 15,000 psi and temperatures of 350 degrees Fahrenheit and volumes of 600cc.
 - **Limitation :**
 - High cost
 - Not recommended for saturated oil reservoirs and depleted gas-condensate reservoirs as they may collect disproportionate amount of liquid or gas downhole.
 - Correct positioning of sampler with respect to depth is required so that it only collects the hydrocarbon samples. Hence prior to sampling a temperature-pressure survey is run in order to determine the oil-water interfaces providing an indication of oil-water contact (OWC) with respect to depth. Once OWC depth relation is established, the sample can be captured above the OWC.

7.3 Wellhead Sampling

- Only possible for fluids that are single phase under wellhead conditions, for example, dry gases, wet gases, or strongly undersaturated oils.
- Therefore some information on the phase envelope of the fluid must be available in advance.
- Because if the sample is flowing in two phases at the wellhead, then a disproportionate ratio of gas and liquid may be collected, and this may differ from that existing in the reservoir.

7.4 Surface(Separator) Sampling

- Relatively low cost.
- Convenient and any fluid type can be collected.
- Has a potential for obtaining cleaner samples as a result of large volumes of fluid production before sampling.
- The well-conditioning recommendations are also applicable for separator sample.

- Factors such as separator efficiency (imperfect separation and liquid carryover in gas and vice versa) and uncertainties in gas and oil rate measurements can affect sample quality.
- The gas and oil samples are simultaneously drawn from a test separator or first stage separator(fig13.3)
- These individual samples are then physically recombined as per the producing GOR to create the live fluid or reservoir fluid for PVT tests.
- The separator oil is collected in a floating piston sample cylinder having capacity 600cc, temperature 300-400 degree Fahrenheit and pressure rating 15,000 psi.
- Floating piston separates the sample and the hydraulic fluid (water or water-glycol mixture).
- Initially the floating piston is at top, subsequently moving backwards as the sample is drawn into the sample side by displacing the hydraulic fluid with the bottom valve in open position.
- The separator gas samples are collected in evacuated (to avoid air contamination) large volume cylinders because of the larger volume required in the recombination due to compressibility of gas.
- The record of collected separator samples are provided which include information like gas and liquid flow rates and separator temperature and pressure at the time of sampling.
- This information helps in recombination process.

7.5 Quality Checks

- The most common validity check is the measurement of bubble-point pressure at surface temperature or reservoir temperature at the field location in a mobile PVT lab before shipping off for detailed studies.
- If the bubble-point pressure at surface temperature exceeds sampling pressure or that at reservoir temperature exceeds reservoir pressure then this indicates that the sampling device has either leaked oil or collected free gas.
- The separator gas and oil are considered under equilibrium at separator temperature and pressure.
- This means that the dew point and bubble point of the separator gas and oil should be equal to the separator pressure at separator temperature. This is another quality check.

7.6 Factors Affecting Sample Representativity

- Oil Based Mud(OBM) : If the well has been drilled with OBM and has not been pumped for a sufficient time to clean up the contaminate, then samples will be contaminated.
- Heavy Organics : The presence of heavy organic solids such as asphaltenes and waxes in petroleum reservoirs can change temperature, pressure and composition leading to precipitation and subsequent deposition of asphaltenes and waxes at certain points in production system such as tubing or separator and hence resulting in alteration.
- Mishandling : Happens when samples are drawn under incorrect pressure and temperature conditions between different stages.
- This might leads to the conversion of a particular condensate to gas and when recombination is done, the resultant is a non-representative of the reservoir fluid and the entire operation fails.

8.0 PVT ANALYSIS AND RESERVOIR FLUID PROPERTIES

Physical property and phase behaviour PVT data provide the necessary information to properly manage the reservoir production. Initial measurements of fluid compressibility and shrinkage factor are required to :

- Determine oil in place and gas in place.
- Provide input for recovery estimates.
- Evaluate reservoir material balance calculation. Understanding fluid behaviour in the reservoir requires constant composition expansion and differential liberation or constant volume liberation measurements. Fluid behaviour influences both recovery and costs compositional analysis and the physically measured fluid properties are used as input and the basis of tuning EOS modelling software. This complete dataset can be used to :
 - Understand the phase behaviour.
 - Evaluate various production scenarios.
 - Optimize reservoir productions and oil recovery schemes.
 - Maximise ultimate recovery.
 - Optimize production economics.

Separate tests simulate the gas and liquid separation of the reservoir fluid at the surface conditions. Results generated include GOR for each separator stage, liquid shrinkage factor and evolved gas properties at each stage. These data are often used in an EOS simulator to optimize separator conditions for maximization of oil production.

In a Pressure-Volume-Temperature lab, researchers employ an arsenal of instrument to determine reservoir fluid behaviour and properties from oil and gas samples. Their goal is to simulate what takes place in the reservoir and at the surface during production. A central aspect of PVT analysis is how gas evolve from oil when pressure falls below bubble point. Researchers use two processes to describe this flash liberation and differential liberation.

In **flash liberation**, a sudden pressure drop causes gas to come out of solution which then remains confined with the oil that is left. In **differential liberation**, gas comes out of solution as pressure is gradually decreased, but is removed from the oil. When reservoir pressure drops below bubble point, flash liberation dominates. Gas comes out of the solution and initially remains in the pores in contact with the oil. Meanwhile, single phase oil continues to flow into the wells although it has slightly different compositions than that of the original reservoir fluid. When enough gas accumulates to reach the critical gas saturation, it begins to flow since gas is less viscous and flows faster than oil, the gas liberation now becomes differential.

8.1 Black oils and Volatile oils

8.1.1 Formation Volume Factor

- The oil formation volume factor, denoted by B_o , is defined as the ratio of the volume of oil at the prevailing reservoir conditions to the volume of oil at standard conditions and is mathematically represented as

$$B_o = (V_o)_{P,T} / (V_o)_{SC}$$

- For B_o values above bubble point pressure, a slight increase is observed as reservoir pressure is reduced. This happens

because the oil in the reservoir simply expands, and this expansion takes place due to the gas still remaining in the solution.

- At bubble point pressure, the oil reaches its maximum expansion and attains maximum value of oil formation volume factor.
- When reservoir pressure falls below bubble point pressure, gas begins to come out of solution, thus leaving less gas in oil and hence resulting in decreasing formation volume factors.
- The reciprocal of oil formation volume factor is called shrinkage factor, denoted by b_o .
- Black oils generally contain small amounts of gas in solution, resulting in smaller values of B_o . Hence less shrinkage is observed and these are called low shrinkage oils.

8.1.2 Solution Gas-Oil Ratio or Gas Solubility

- Gas solubility, denoted by R_s , is defined as the quantity of gas dissolved in an oil at reservoir pressure and temperature.
- At bubble point pressure and all pressures above the solution gas-oil ratio remains constant.
- When reservoir pressure falls below bubble point, the oil is saturated and cannot contain all the gas in the solution, resulting in release of gas.
- If reservoir pressure and temperature is reduced to atmospheric conditions most of the gas in the oil comes out. If all gas that evolves in this reduction is Y and volume of oil is X . Then gas-oil ratio is Y/X .

8.1.3 Total Formation Volume Factor

- The total or two-phase formation volume factor, denoted by B_t , is used to express the ratio of total gas and oil volume at reservoir conditions to the stock tank oil volume and, thus by definition, applicable at all pressures below the bubble point since the oil splits into two phases. Mathematically B_t can be represented as

$$B_t = B_o + B_g(R_{sb}-R_s)$$

where B_t is the total formation volume factor

B_o is the oil formation volume factor

B_g is the evolved gas formation volume factor

R_{sb} is the solution gas oil ratio at bubble point

R_s solution gas-oil ratio at pressure < bubble point

8.1.4 Viscosity

- Oil viscosity, denoted by μ_o is also dependent on pressure and temperature.
- An increase in temperature causes decrease in oil viscosity.
- A decrease in pressure causes a decrease in viscosity. This rule is strictly obeyed at bubble point pressure and above because all gas remains intact in solution with oil.
- Below bubble point pressure, the amount of gas remaining in solution continually decreases with pressure and has an opposite effect on oil viscosity. Oil viscosity increases with decreasing pressure.
- As black oil reservoir is depleted, not only does the production decrease due to the decrease in the driving force of pressure and competition between free gas but also because of the increase in the oil viscosity.

8.1.5 Surface Tension

- When miscible injection processes are considered for enhanced oil recovery, they rely to a great extent on the interaction between displacing gas and in-place fluids (oils) producing low surface tension values.
- The surface tension between gas and oil is normally denoted by σ_{go} .
- Surface Tension is affected by properties like composition and densities.
- At pressure above bubble point, only oil is present in single phase and no gas is evolved, the surface tension is 0.

Volatile oils have the same definition for all the properties defined above. The only difference in black oils and volatile oils is the difference between

the magnitudes of these properties. Volatile oils contains significant portion of dissolved gas, meaning large amount of gas evolution takes place at pressure below bubble point indicated by closely spaced iso-vols.

8.2 Laboratory Tests

- Valid fluid sample is available for tests, either through a single-phase sample in the field (bottomhole sample) or through recombination of separator gas and liquid in the laboratory.
- The validation of field samples and recombination is also integral parts of the laboratory tests because the representativity of measured data is dependent on the quality of the fluid samples.
- All laboratory tests are designed to characterize the phase behavior and properties of reservoir fluids at simulated reservoir conditions.
- Although water is almost always present in petroleum reservoirs, its effect on phase behavior and properties is ignored in most tests. Hence reservoir fluid studies are conducted in the absence of water.

8.2.1 PVT Equipment

- All laboratory tests are generally conducted in conventional PVT equipment.
- Most essential component of any PVT equipment is a PVT cell. It is usually cylindrical and made of special grade stainless steel or titanium that is equipped with a mechanism to increase or decrease the cell volume thereby altering the pressure.
- The alteration of cell volume is usually achieved via a mechanically driven piston or mercury.
- The PVT cell is housed in a thermostatic enclosure or an air bath, where air can be cooled or heated to maintain a constant test temperature. This basic PV mechanism allows depletion experiments to be conducted on any given reservoir fluid.
- The volume of the PVT cell, ranging from 50-5000cc is a function of the type of reservoir fluid to be tested. For example, gas condensates generally require a large volume

because we need to measure small liquid-phase volumes in equilibrium with a very large volume of vapor phase.

- (fig15.16)The two PVT cells are arranged in the form of an hourglass shape. The stem of the hourglass connects with the two PVT cells and serves as a window through which visual observations can be made. Mechanically driven pistons control the volume available for hydrocarbon fluids within the two cells. The entire assembly and the associated tubing are housed in a forced convection air bath for maintaining constant test temperature.
- The measurements of properties of the single-phase fluid or the equilibrium phases is normally achieved by passing the fluids through an analysis loop that consists of a densitometer, gas chromatograph, capillary tube viscometer.

8.2.2 Constant Composition Expansion

- It is carried out in all PVT studies irrespective of the fluid type.
- The overall composition of the reservoir fluid or its original mass always remains constant because none of the test fluid is ever removed from the PVT cell.
- The primary objective of this test is to study the PV relations of a given reservoir fluid and determine its saturation pressure.
- A single phase sample of reservoir fluid is loaded in a PVT cell.
- The loaded sample is pressurized to a value equal to or greater than the initial reservoir pressure, and the air bath temperature is set at reservoir temperature.
- The sample is typically stabilized at these conditions by operating the pump in a constant pressure mode.
- After the pressure and temperature conditions are stabilized, a pressure depletion experiment is carried out by increasing the volume in increments.

- The cell contents are agitated regularly to aid the equilibration process.
- The total and phase volumes of the hydrocarbon system are recorded at each pressure step.
- The depletion process continues in this fashion until a predetermined low pressure or capacity of the cell is reached.
- The pressure at which the slope changes is the bubble point pressure of the oil.
- This change in slope occurs for two reasons:
 - In the single phase region, the oil is incompressible, resulting in a large pressure reduction with small volume increase.
 - As soon as the bubble point is reached due to compressibility of the newly formed vapor phase, the same magnitude of volume increase causes less reduction in pressure.

8.2.3 Differential Liberation

- The experiment is carried out at reservoir temperature to evaluate the volumetric and compositional changes that take place in the oils during pressure depletion.
- The solution gas that is liberated from an oil sample during decline in pressure is continuously removed from contact with oil.
- Pressure is reduced by increasing the cell volume at a pressure less than the bubble point pressure.
- After achieving stabilization of pressure and temperature conditions and equilibrated volumes of gas and liquid phases, all evolved gas is expelled isobarically by reducing the cell volume.
- This process is repeated in 10-15 stages down to atmospheric pressure.
- At each pressure stage, the remaining oil volume, the expelled gas volume at the cell conditions and standard conditions, and gas specific gravity are measured.

8.2.4 Separator Tests

- Petroleum reservoir fluids existing at high pressure conditions in the reservoir experience pressure and temperature reduction when they are produced at surface.
- As a result of these changes, gases evolve from liquids and the well stream changes its character.
- Separator tests are carried out on reservoir fluids to simulate potential production separator stages and provide volumetric and other data on the stock tank oil and liberated gas streams.
- Separator tests are primarily carried out on black oils and are usually the final tests that are conducted in the lab.
- Sample of reservoir oil at its bubble point pressure is flashed into two stages.
- The first stage represents a separator while the second stage represents the stock tank usually at atmospheric pressure.
- For oils that contain a high gas in solution, separation is carried out in multiple stages to reduce the pressure on reservoir fluid a little at a time and also to obtain a stable final liquid product.
- The separator test is conducted at temperatures that represent the average field condition.
- The separator test is usually carried out at a number of separator pressures in order to determine the optimum field separator conditions.
- The three main parameters determined in this test are :
 - The formation volume factor of oil B_{oSb}
 - The solution gas-oil ratio R_{sSb}
 - The specific gravity of the stock tank oil

B_{oSb} is the ratio of volume of liquid expelled from the cell to the volume of liquid arriving in the stock tank.

R_{sSb} is the ratio of volume of separator gas and stock tank gas to the volume of liquid in the stock tank.

8.3 PVT Study of Sub-Surface Sample

The reservoir sample is sent to lab to analyse the reservoir fluids characteristics. In labs the following process takes place :

8.3.1 Determination of valve opening pressure

Sampling is generally done in 2 or 3 bottom hole samplers and it is sent to laboratory. At the laboratory, the selection of the most representative sample is done as prescribed below :

- If the valve opening pressure (VOP) of all the samplers are same, then all are representative samples and anyone of them can be used for detailed phase behaviour studies.
- If VOP of all the samplers are different, then one whose GOR is not available and the sample having highest VOP is considered most representative sample for phase behaviour studies.

8.3.2 Transfer of Sample into PVT cell from Shipping Bottle

- Note down the room and cell temperatures.
- After ensuring the sufficient quantity of hydraulic fluid in reservoir of the transfer pump, attach this transfer pump to the bottom valve of the shipping bottle.
- Top valve of the shipping bottle is to be connected to the top valve of the PVT cell which is already completely filled with the piston in the cell at minimum position, to take the reservoir fluid from the shipping bottle to the cell.
- Entire transfer system is at the charged pressure while transferring the reservoir fluid into the PVT cell from the shipping bottle, running both the pumps carefully and slowly.
- Approximately 110cc of reservoir fluid is taken into the cell and accurate volume at charging condition is noted down.

8.3.4 Bringing Cell Temperature to Reservoir Temperature

This is done by switching ON the oven and set temperature to reservoir temperature. The heat is transferred from the oven to the cell and the cell attains reservoir temperature. Now, the sample in

the cell has reservoir characteristics i.e. reservoir temperature and pressure. It is ensured that single thermodynamically stable phase is attained at reservoir conditions in the PVT cell.

8.3.5 Density of Reservoir Fluid

A fluid at reservoir conditions is charged from a PVT cell to the HP/HT density measuring cell. The temperature is regulated by a thermostatic bath. Measurements can be taken at desirable temperature and pressure, recorded, stored and transferred to a computer for further processing.

- To calibrate densitometer using nitrogen and water as standards.
- Put up the density of nitrogen and water from standard density table in the DMA-HPM software.
- It will give the value of two constants (say A and B) on DMA screen.
- Now connect inlet of measuring cell to PVT cell and flow the oil into the measuring cell.
- By using the obtained constants, software automatically calculates the density of fluid.

8.3.6 Isobaric Thermal Expansion Studies

It is determined at reservoir pressure by measuring the volume of fluid at two different temperatures namely 40 degree celcius and reservoir temperature to know the shrinkage of reservoir fluid due to drop in temperature as the fluid is produced at the surface.

8.3.7 Constant Mass Expansion Studies

The confining pressure above the reservoir pressure is reduced in stages and corresponding volume is recorded. As the pressure is reduced, there is a gentle increase in the volume of the system. This trend continues till the system pressure reaches the bubble point pressure and just below the bubble point pressure there is a sharp increase in the volume of the system. At the bubble point pressure, gas begins to bubble out from the liquid and the two phases appear.

8.3.8 Single Stage Flash Liberation Study

The fluid sample is flashed at reservoir temperature and little more than reservoir pressure to determine GOR, FVF, Density. The initial temperature for this process is reservoir temperature and the pressure is above the reservoir pressure. In this the sample is allowed to flow out of the cell in the separator which is at room temperature and atmospheric pressure. The sample flow to the separator until the desirable amount of sample gets accumulated in the separator. The sudden pressure drop causes the gas to evolve in the separator which after attaining equilibrium is liberated to the gasometer. So the FVF can be determined by anticipating the volume of oil that is accumulated in separator and the volume of oil that is withdrawn from the cell. The flashed oil and gas is analysed on gas chromatograph for their composition.

8.3.9 Differential Vaporisation Studies

These studies are carried out at different pressures below bubble point. The gas which is liberated upon reduction in confining pressure is continuously removed (without oil) in a systematic and precise manner before establishing of thermal equilibrium and is metered. The pressure is decreased to a minimum extent. The data is used to calculate Z-factor, FVF and P-V relationship of the gas. Gas liberated during these process are analysed on gas chromatography for its composition.

8.3.10 Viscosity Study

Fluid at the working pressure above the reservoir pressure and at reservoir temperature, a fluid is charged to a PVT cell and subsequently to capillary viscometer with the absolute viscosity measured at various pressure stages above the saturation. The fluid is then degassed stepwise, with a viscosity measurement at each stage down to stock tank condition. A final plot of viscosity versus pressure is generated.

