iJRASET
International Journal For Research in
Applied Science and Engineering Technology

INTERNATIONAL JOURNAL FOR RESEARCH

IN APPLIED SCIENCE & ENGINEERING TECHNOLOGY

Volume: 9 **Issue:** IX **Month of publication:** September 2021

DOI: https://doi.org/10.22214/ijraset.2021.37933

www.ijraset.com

Call: 08813907089 | E-mail ID: ijraset@gmail.com

International Journal for Research in Applied Science & Engineering Technology (IJRASET)
ISSN: 2321-9653; IC Value: 45.98; SJ Impact Factor: 7.429
Volume 9 Issue IX Sep 2021- Available at www.ijraset.com

Laboratory Measurements of Total Organic Carbon (TOC) and Petrophysical Properties of Drilled Core Samples

Rasaiah Pragalathan[1], Pran P. P[2]
[1, 2]Anna University

I. INRODUCTION ON ONGC - CAUVERY ASSET

A. Introduction To Geology Of Cauvery Basin

On the east coast of Southern India, in the state Tamil Nadu, of large alluvium covered coastal belt along Coromandel coast including Gulf of Mannar, Palk Bay forms the Cauvery basin. The basin encompasses a total area of around 62,500 sq.km up to a bathymetry of 200m in the Bay of Bengal. The basin is roughly 100 to 150 km wide in E-W direction and 400 km long in N-S direction. The basin evolved as a composite of rifted graben since Late Jurassic and formed a part in the development of East Coast divergent margin of India. Towards eastern margin of the basin few isolated outcrops of Mesozoic and Tertiary sedimentary rocks are seen near Sivaganga, Ariyalur, and Vrudhachalam and Pondicherry areas. The exposed sedimentary rocks along western margin prompted the Geoscientists of ONGC to initiate exploration in 1958 followed by geophysical surveys in 1960.

Twenty years of active exploration has led to the drilling and finding of non-commercial oil strike in 1977 (Karaikal). However, enormous amount of data generated during this period warranted restudy and reinterpretation, a drilling holiday was thus declared between 1977 and 1984. Second phase of drilling commenced in 1984. The next year itself has led to the discovery of two important fields Narimanam and Kovilkalappal. Since then ONGC has never looked back in its exploratory efforts in finding oil and gas fields, across the basin.

B. Intoduction To Cauvery Asset

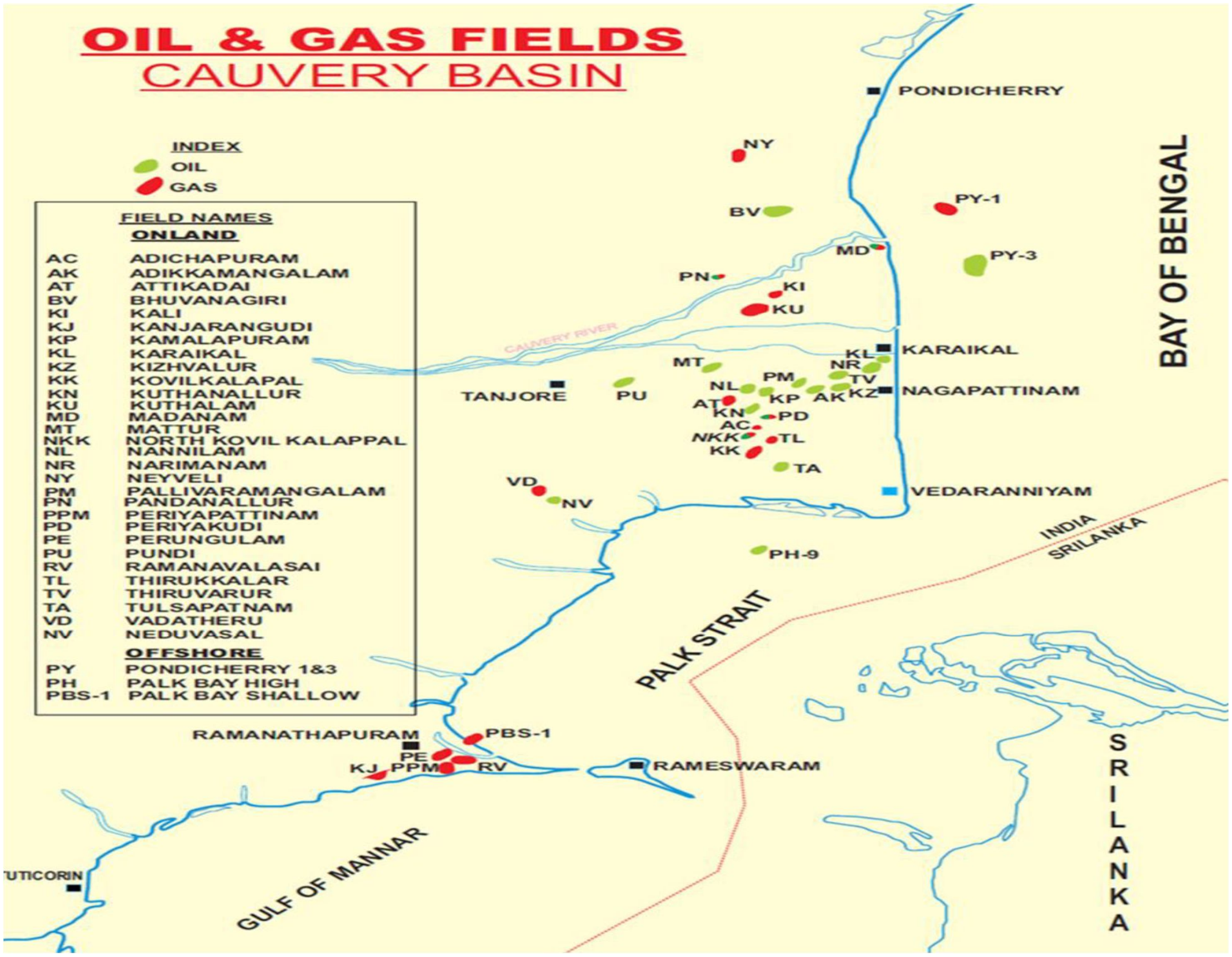
The Oil and Gas exploration giant ONGC occupies a pride of place among India’s Maharatna Companies. Within ONGC, the 'Cauvery Asset', hub of Production and Development activities in the remote Southern most parts of India are one of the success stories in its relentless pursuit of oil and gas. Cauvery Asset is based at Karaikal. ONGC's presence in this region has given a boost to Industrial Development in the districts of Nagapattinam, Karaikal, Tiruvarur, Ramnadu and Cuddalore. The mushrooming of Steel Units, Power Generation Stations, and ceramic industries in these areas bear testimony to this. Private and Public Sector power generation stations operate on gas supplied from ONGC’s oil and gas fields. A number of private players apart from TNEB have set up gas-based power projects in this area, using gas from ONGC generating more than 800 MW power. A further feather in the cap for the Cauvery Asset is the sale of Sour gas from Narimanam and Kovilkalappal fields.

The Cauvery Basin covers an area of about 25000 sq.km in the Onshore and extends from Puducherry in the North to Ramnad in the South and Thanjavur in the West to Karaikal in the East. Intense geological processes taking place beneath the sands of this Cauvery Basin have made it the home for the Hydrocarbons. Hydrocarbons in the form of oil and gas are found in reservoir pockets distributed all over this vast basin. The basin is under active exploration and development of oil and gas pools with the deployment of nine drilling rigs and four workover rigs dedicated to the revival of sick wells. The main constraint in this basin is that there are multiple thin layers of Sand hosting the Reservoirs rather than thick Blanket Sands, such as encountered in the Assam Shelf which lend themselves to Reservoir mapping and Interpretation more easily, thus facilitating Development activities. Cauvery Basin has much smaller oil and gas pools.

C. Exploration

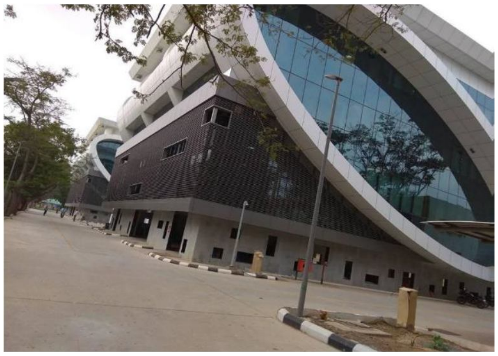
ONGC's exploration activities in Cauvery Basin started nearly fifty years ago, in 1958 to be precise. The exposed sedimentary rocks along the western fringe of the basin prompted the geoscientists of ONGC to initiate exploration for Hydrocarbons. Drilling began in 1964 and the first taste of success came with the finding of oil in the well 'Karaikal in 1977. Twenty years of active exploration had yielded copious geo-scientific data. Immediately after this, in order to review and reinterpret the findings, a drilling holiday was declared in 1977. After a detailed review of all available data, the second phase of drilling commenced in 1984. Success greeted the dedicated workforce of ONGC, almost immediately, with the discovery of Kovilkalappal and Narimanam fields, in 1985. Cauvery Basin had emerged on the oil map of the country.

This major breakthrough brought the basin into exploratory focus. The rejuvenated exploratory efforts resulted in drilling 618 wells as on 01.02.2012 out of which 144 are oil and 96 are gas wells. This has led to the discovery of 29 oil and gas fields, the milestones of this basin. They are: Karaikal (1977), Kovilkalappal (1988), Adiyakkamangalam (1989), Kamalapuram and Tiruvarur (1990), Mattur, Athikadai, Vadatheru and Vijayapuram (1992), Pallivaramangalam and Kuttanallur (1993), Perungulam (1994), Pundi (1995), Kizhvalur and Kuthalam (1996), Tulsiapatnam, Periyapatnam, Neyveli and Ramanvalasai (1997) and Kali (1998), Kuthalam satellite fields (1999), Kanjirangudi (2000), Palk Bay Shallow-Offshore (2001), Adichapuram (2007), Periyakudi(2010), Madanam & Pandanallur (2012).



D. Introduction On Regional Geoscience Laboratory, ONGC

It is a prestigious geological laboratory working for ONGC, Cauvery Basin.



E. Laboratories

1) Geology Laboratory

a) Sedimentology Laboratory: In this laboratory the lithology of the rock can be predicted with the help of

- Mega Scope
- Petro Scope
- SEM (Scanning Electron Microscope)

b) Palynology & Paleontology Laboratory: In this laboratory, Age and Depth of the rock can be predicted.

2) Chemistry Laboratory

a) Cement Laboratory: Design of Cement Slurry.

b) Quality Control and Drilling fluid Laboratory: Analyzing the Mud properties.

c) Source Rock Laboratory: Testing of Total Organic Components (TOC) present in the rock sample.

d) Phase Behaviour Laboratory (PVT): Determining the fluid behaviour and properties of oil and gas sample from an existing well.

II. OIL AND GAS EXPLORATION & PRODUCTION

A. Introduction To Oil And Gas

The petroleum industry, also known as the oil and gas industry includes the global processes of exploration, extraction, refining, transporting. The industry is divided into three major stages:

1) Upstream
2) Midstream
3) Downstream

Upstream is also known as exploration and production stage and involves the search for underwater and underground oil and gas deposits. The drilling of exploration wells is the main activity of this stage.

The second stage, midstream, refers to the collection and transportation of crude oil, natural gas, and refined products, usually via pipeline, oil tanker, barge, truck or rail. This stage also includes the storage of products as well as any wholesale marketing efforts.

Downstream refers to the filtering of the raw materials obtained during the upstream phase. This means refining crude oil and purifying natural gas. The marketing and commercial distribution of these products to consumers and end users in a number of forms including natural gas, diesel oil, petrol, gasoline, lubricants, kerosene, jet fuel, asphalt, heating oil, LPG (liquefied petroleum gas) as well as a number of other types of petrochemicals.

B. Hydrocarbon Formation

A hydrocarbon is an organic compound consisting entirely of hydrogen and carbon. The Formation of hydrocarbons is a slow process. It takes millions of years for decaying organic matter to be transformed into hydrocarbons within source rock. As sedimentation occurs, chemical reactions create the carbon and hydrogen molecules that make up liquid or gaseous hydrocarbons.

The hydrocarbons then slowly travel upwards until they are trapped by impermeable rock and form a deposit in a reservoir.

Most hydrocarbons found on Earth naturally occur in crude oil, where decomposed organic matter provides an abundance of carbon and hydrogen which, when bonded, can catenate to form seemingly limitless chains.

The predominant use of hydrocarbons is as a combustible fuel source. In their solid form, hydrocarbons take the form of asphalt (bitumen). Methane (CH4) and ethane (C2H6) are gaseous at ambient temperatures and cannot be readily liquefied by pressure alone. Propane (C3H8) is however easily liquefied, and exists in 'propane bottles' mostly as a liquid. Butane (C4H10) is so easily liquefied that it provides a safe, volatile fuel for small pocket lighters. Pentane (C5H12) is a colorless liquid at room temperature, commonly used in chemistry and industry as a powerful nearly odorless solvent of waxes and high molecular weight organic compounds, including greases. Hexane (C6H14) is also a widely used non-polar, non-aromatic solvent, as well as a significant fraction of common gasoline.

C. Five Major Types Of Hydrocarbon

1) *Kerogen:* Kerogen is a fine-grained, amorphous organic matter. It is not soluble to normal petroleum solvents, like carbon disulfide. Its chemical composition is 75% C, 10% H, 15% other (sulfur, oxygen, nitrogen, etc.). It is very important in the formation of hydrocarbons because it is what generates oil and gas. Source rocks must contain significant amounts of kerogen.

2) *Asphalt:* Asphalt is a solid at surface temperatures. It is soluble to petroleum solvents. It is produced by the partial maturation of kerogen or the degradation of crude oil.
3) *Crude Oil:* Crude oil is a liquid at surface temperatures. It is soluble to normal petroleum solvents. It has four main groups of organic compounds: paraffin, naphthalene, aromatics, and resins.
4) *Natural Gas:* Is a hydrocarbon gas. The major natural gases are methane, ethane, propane, and butane.
5) *Condensates:* These are hydrocarbons transitional between gas and crude oil.

D. Migration Of Hydrocarbon

There are numerous factors controlling the hydrocarbon migration process like kerogen expansion, increase in pressure and hydrocarbon expulsion out of source rock. The expulsion of the oil out of the source rock is a dynamic process driven by the oil generation itself. Good source rocks have TOC (total organic content) ranging from 3 to 10%.

At low TOC, the kerogen may occupy a position within the matrix porosity of the rock. At high TOC, the kerogen can form connected bands within the rock. Then, the kerogen is bearing part of the lithostatic load. As the organic matter transforms into oil, this load-bearing kerogen turns into liquid. The fluid pressure of the oil within the black shales can become high enough to produce micro fractures in the rock. Once the micro fractures form, the oil is squeezed out and the source rock collapses. So, primary migration can be viewed as a second episode of compaction. Micro fractures of this type can be seen in the most productive source rocks and they are often filled with remnants of oil.

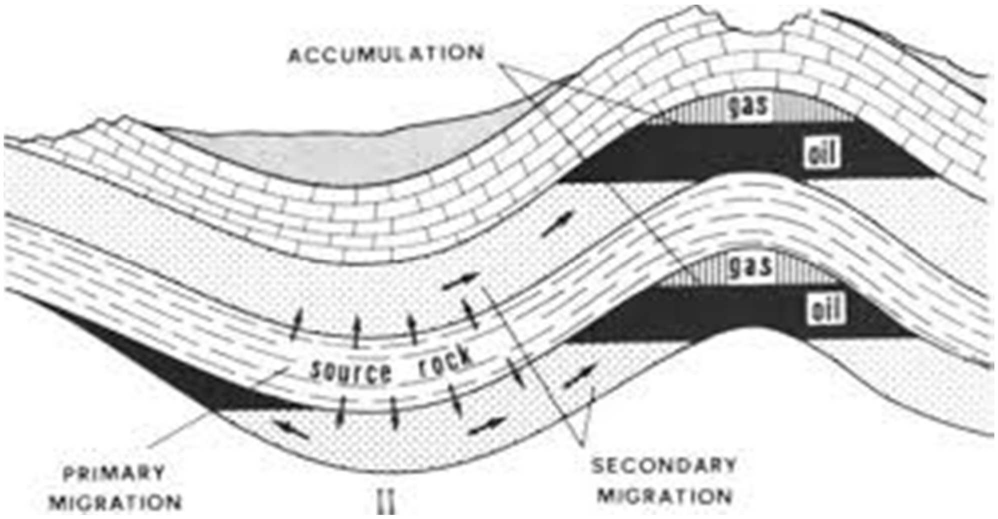
E. Migration Types

There are three major types of hydrocarbon:

1) *Primary Migration:* Primary migration of hydrocarbons is the movement of oil and gas from source rock to permeable carrier beds
2) *Secondary Migration:* Secondary migration is the movement from permeable carrier beds to the reservoir beds. Secondary migration occurs through porous rocks due to buoyancy and capillary and regional pressure gradients.
3) *Tertiary Migration:* Tertiary migration is a migration that occurs when petroleum moves from one trap to another or to a seep.

F. Five Parameters For Hydrocarbon Accumulation

1) Source rocks are required to generate hydrocarbons. Generally, has greater than .5% organic matter (kerogen) by weight.
2) Reservoir rocks are required to store hydrocarbons.
3) Seal or cap rocks are present to prevent the upward escape of hydrocarbons from reservoir.
4) Traps occur where the source, reservoir and seal are arranged in a way that the hydrocarbons can move from the source to the reservoir.
5) Source rock must have been heated sufficiently for oil greater than 60ºC and for gas greater than 150ºC.



G. Three Phases Of Alteration Of Organic Matter

1) *Diagenesis:* Diagenesis occurs at the surface at normal temperatures. The organic matter goes under bacterial decay, oxidation, dehydration and decarboxylation. The resultant is kerogen. The porosity decreases 60% to 40%.
2) *Catagenesis:* Temperatures increase to 250ºC and kerogen generates oil or gas. The porosity decreases to 10%. Catagenesis is the most important stage, and is different for the three different types of kerogen.
3) *Metagenesis:* Occurs at 250ºC right when the kerogen is going to change into oil or gas.

H. Kerogen And Its Types

Kerogen is the portion of naturally occurring organic matter that is non-extractable using organic solvents. Typical organic constituents of kerogen are algae and woody plant material. Kerogens have a high molecular weight relative to bitumen, or soluble organic matter.

1) *Type I (Algal):* It is very rich in hydrogen, low in oxygen and contains lipids. It generates oil and is present in oil shales.
2) *Type II (Leptonic):* It is made from algal detritus, phytoplankton and zooplankton. It has aliphatic compounds and more hydrogen than carbon. It can generate oil or gas.
3) *Type III (Humic):* It has more carbon than hydrogen, and is rich in aromatic compounds. It is produced form lignin in higher woody plants. It generates gas.

Type I and Type II are usually found in marine environment and Type III is found in continental environments. That is why there is the generalization that marine produces oil and continental produces gas.

I. Oil And Gas Exploration & Production

An exploration & production (E&P) company is in a specific sector within the oil and gas industry. Companies involved in the high-risk/high-reward area of exploration and production focus on finding, augmenting, producing, and merchandising different types of oil and gas.

Exploration and production (E&P) is known as the upstream segment of the oil and gas industry. The resource owners and operators of E&Ps work with a variety of contractors such as engineering procurement and construction (EPC) contractors, as well as with joint-venture partners and oil field service companies, and as E&P operators produce oil and gas, they also build infrastructure and collect massive amounts of analytical data.

J. E&P Stages

Exploration & production companies locate and extract resources from the Earth; the process of oil and gas exploration and production typically involves four stages,

1) *Exploration:* At this stage, the search for hydrocarbons beneath the ground entails geophysical prospecting for shale formations that hold deposits of oil and natural gas. One method of exploration involves seismology, a process whereby substantial vibrations, via explosives or machinery, are produced at the Earth's surface. Seismic waves travel to the Earth's mantle, and the respondent force is analyzed at the surface to identify layers of rock that trap reservoirs of oil and natural gas.
2) *Well Development:* After identifying potentially viable fields, engineers determine the number of wells needed to meet production requirements and the method of extraction of the liquid hydrocarbons. Platform construction costs are estimated with regard to the site, offshore or onshore, and designs are rendered for systems used to facilitate environmental protections. Newer drilling technologies, prominent in the Marcellus and Bennett shale fields in Pennsylvania and Texas, allow companies such as Chesapeake Energy Corporation to extend horizontal legs about 5,000 feet from vertical wells in search of natural gas pockets, producing four times as much gas at only twice the cost of a vertical well.
3) *Production:* Liquid hydrocarbons extracted from wells are separated from the non-saleable components such as water and solid residuals. Natural gas is often processed onsite while oil is piped to a refinery before being offered for sale.
4) *Abandonment:* As exploratory sites are deemed unproductive or existing operations exhaust capacity, companies plug wells and attempt to restore the areas to environmental states that existed prior to drilling activities. As natural gas prices descended to historic lows in January 2016, many exploratory wells were shuttered as high production costs rendered extraction unprofitable.

III. IMPORTANCE OF GEOLOGY TO THE OIL AND GAS INDUSTRY

The science of geology is one of the fundamental sciences of petroleum engineering. Some of the other fundamental sciences of petroleum engineering are mathematics, physics, and chemistry, Other, “applied sciences” like strength of materials, fluid flow, heat transfer, thermodynamics, and physical chemistry also are essential in various aspects of the practice of petroleum engineering in the business world. Geology is an important element for the petroleum engineer.

The word petroleum itself comes from two Greek words "Petra" meaning rock and "oleum" meaning oil. So, petroleum can be summarized to layers as oil found in rocks. Geology being a science these rocks makes it a fundamental and integral part of petroleum engineering.

A. Rock Cycle

The rock cycle is a process in which rocks are continuously transformed between the three rock types igneous, sedimentary and metamorphic.

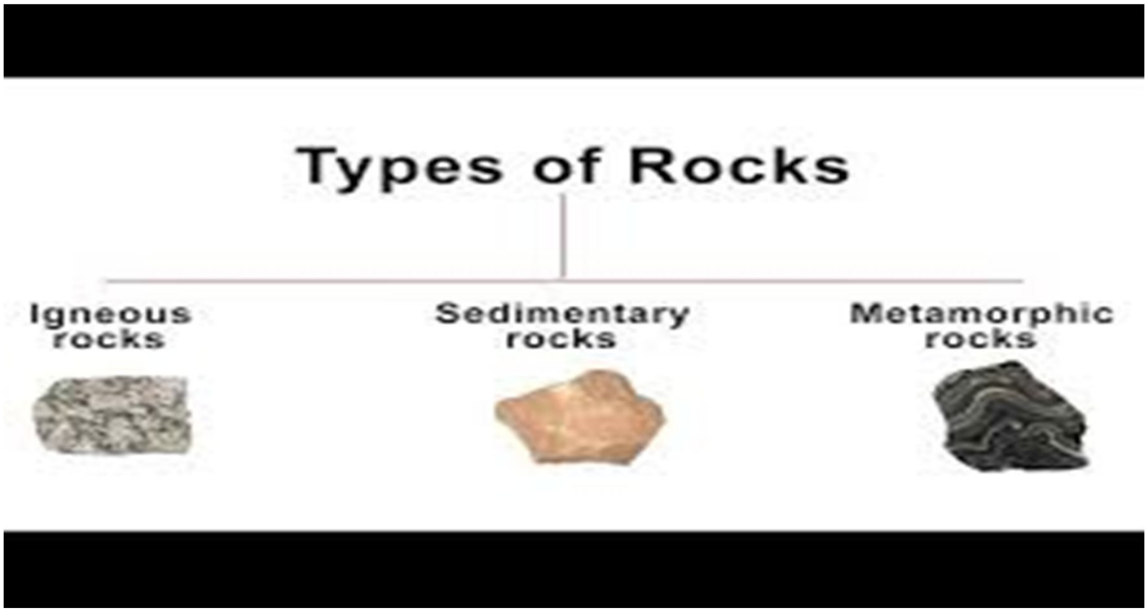
Rocks of any type can be converted into any other type, or into another rock of the same type.

Conversion to metamorphic rocks requires conditions of increased temperature and/or increased pressure, conversion to sedimentary rocks occurs via the intermediate stage of sediments, and conversion to igneous rocks occurs via the intermediate stage of magma.

Increased temperature and pressure occur in subduction zones and in areas where two plates of continental lithosphere collide to produce a mountain range, while increased pressure without increased temperature is produced when sedimentary rocks are deeply buried under more sediments. Sediments are produced when rocks are uplifted, weathered and eroded, and the resulting detrital material deposited in marine or terrestrial basins.

If the sediments are buried under further layers of sediment, they can become lithified to produce a sedimentary rock. Magma is produced when rocks are melted. This melting can occur when a lithospheric plate descends into the Earth’s crust at a subduction zone, or when a mid-ocean ridge opens up and produces decompression melting in the asthenosphere under the ridge. When the magma solidifies, it becomes an igneous rock.

B. Types Of Rock



1) *Igneous:* They form from the cooling of magma deep inside the earth. They often have large crystals (you can see them with the naked eye).
2) *Metamorphic:* They are formed through the change (metamorphosis) of igneous and sedimentary rocks. They can form both underground and at the surface.
3) *Sedimentary:* They are formed through the solidification of sediment. They can be formed from organic remains (such as limestone), or from the cementing of other rocks.

C. Igneous Rock

Igneous rocks are formed from the solidification of molten rock material. There are two basic types.

1) Intrusive igneous rocks crystallize below Earth's surface, and the slow cooling that occurs there allows large crystals to form. Examples of intrusive igneous rocks are diorite, gabbro, granite, pegmatite, and peridotite.
2) Extrusive igneous rocks erupt onto the surface, where they cool quickly to form small crystals. Some cool so quickly that they form an amorphous glass. These rock include andesite, basalt, dacite, obsidian, pumice, rhyolite, scoria, and tuff.

D. Sedimentary Rocks

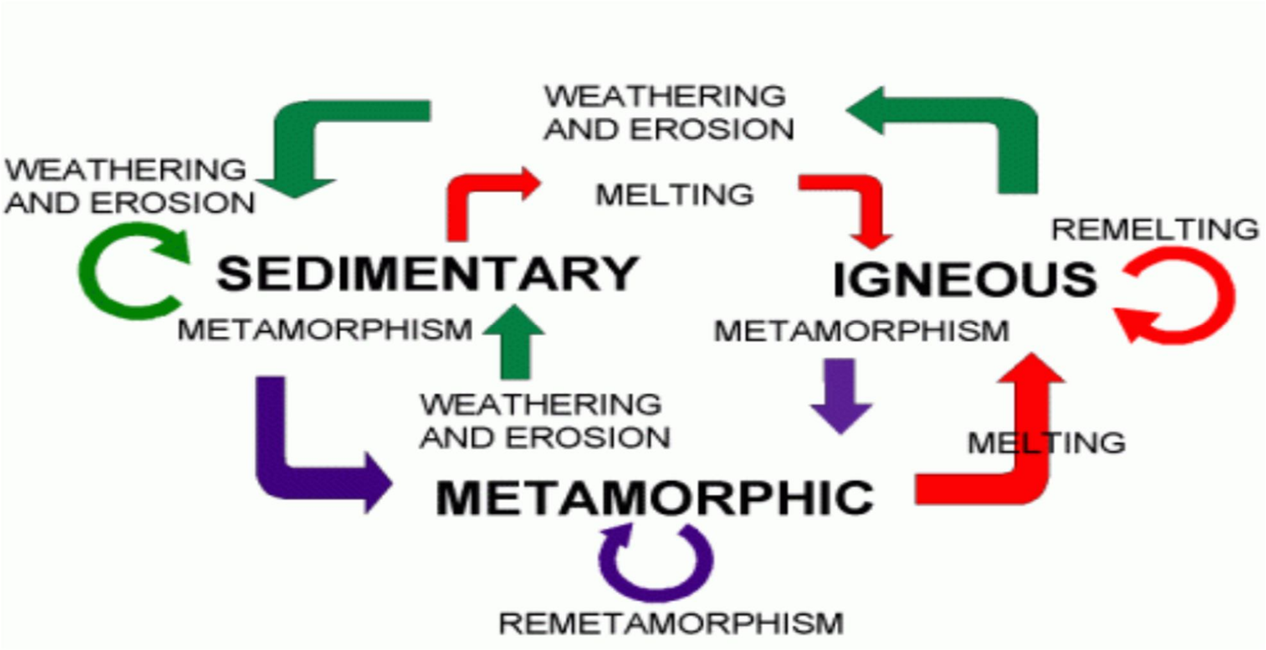
Sedimentary rocks are formed by the accumulation of sediments. There are three basic types of sedimentary rocks.

1) *Clastic Sedimentary Rocks:* Such as breccia, conglomerate, sandstone, siltstone, and shale are formed from mechanical weathering debris.
2) *Chemical Sedimentary Rocks:* Such as rock salt, iron ore, chert, flint, some dolomites, and some limestones, form when dissolved materials precipitate from solution.
3) *Organic Sedimentary Rocks:* Such as coal, some dolomites, and some limestones, form from the accumulation of plant or animal debris.

E. Metamorphic Rocks

Metamorphic rocks have been modified by heat, pressure, and chemical processes, usually while buried deep below Earth's surface. Exposure to these extreme conditions has altered the mineralogy, texture, and chemical composition of the rocks. There are two basic types of metamorphic rocks.

1) Foliated metamorphic rocks such as gneiss, phyllite, schist, and slate have a layered or banded appearance that is produced by exposure to heat and directed pressure.
2) Non-foliated metamorphic rocks such as hornfels, marble, quartzite, and novaculite do not have a layered or banded appearance.



IV. RESERVOIR CHARATERIZATIONS

A. Reservoir Rocks

We can define reservoir rock as one that has porosity and permeability that allows it to contain a significant amount of extractable hydrocarbon.

B. *Reservoir Characterisation*

Reservoir Characterization generally determine the gross volume within the trap that has the potential to hold hydrocarbons. The accuracy of reservoir estimation such as thickness and other Petro physical parameters of each reservoir is a critical element in interpretation. Reservoir characterization can be defined as all the relevant and valuable information necessary for the effective description of a reservoir. The reservoir, by this association, is thus defined in terms of its capacity to store and produce hydrocarbons.

These reservoir properties are classified into two groups: Static (such as porosity, permeability, heterogeneity, net pay, and thickness) and Dynamic (fluid flow within the reservoir).

Such information about the reservoir will help improve production rates, rejuvenate oil fields, predict future reservoir performance, minimize costly expenditure, and help management of oil companies to draw up accurate financial models. Reservoir characterization is an important phase between the discovery of an oil or gas field and the reservoir management phase. Reservoir characterization an interdisciplinary measure which integrates the application of geology, geophysics, reservoir engineering, petrophysics, economics, and data management. The success of reservoir characterization depends on the proper integration, management and application of these disciplines.

The reservoir characterization exercise usually begins with the available geological information and knowledge about the depositional and facies environment. Reservoir characteristics such as natural heterogeneity, spatial variability of permeability and porosity, porous media properties and spatial distribution of hydrocarbon and water predominantly control the flow field, reservoir performance, development strategies, and hence the economic returns of investments, which is the primary concern of the oil companies. The characterization of reservoirs therefore, require the integration of different types of data in order to adequately define the reservoir model.

C. *Petro Physical Properties*

1) *Lithology Identification:* The user will be able to interpret the lithology by using several logs, there are gamma ray, spontaneous potential, resistivity, and density log. Basically, a formation with high gamma ray reading indicates that it is a shaley or shale, when the low gamma ray reading indicates a clean formation it is sand, carbonate. lithology interpretation is very important in reservoir characterization because, if the lithology interpretation is already wrong, the other steps such as porosity and water saturation calculation will be a total mess. The evaluation of the petrophysical properties starts with identifying the economic zones (i.e. clean sand with sizable quantity of hydrocarbons). The lithology (sandstone and shale) were identified using the gamma ray log with reference to sand/shale baseline. The percentage sand/shale is computed from the gamma ray log using the equation below.

The % (shale/sand) is computed from the gamma ray log as:

Where,

% shale = Percentage volume of shale in the formation

GR log = Gamma Ray Log Reading

GR max = Gamma Ray Log Reading in Shale Zone

GR min =Gamma Ray Log Reading in clean Sand Zone.

From the above equation,

%sand =100% - %shale

2) *Volume Of Shale:* Volume of shale mentions to the volume of shale existing in a formation. Sand and carbonate are usually less radioactive than the shale thus gamma ray log can be used to calculate volume of shale in porous reservoirs. The volume of shale is expressed as a decimal fraction or percentage and denoted by Vsh. Gamma Ray Index is the first step to determine the volume of shale from a gamma ray log, shown in equation

IGR= (GRlog- GRmin) / (GRmax- GRmin)

Where:

IGR = gamma ray index

GRlog = gamma ray reading of formation

GRmin = minimum gamma ray (clean sand or carbonate)

GRmax = maximum gamma ray (shale) for a first-order estimation of shale volume, the linear response, where Vsh = IGR, should be used.

3) *Hydrocarbon Or Non-Hydrocarbon Bearing Zones:* The combined density and neutron log were used for the identification and characterization of the various fluids in the formation, i.e. hydrocarbon from non-hydrocarbon bearing zones, Gas zones are identified from the balloon effect (cross over) of the neutron and density logs. The resistivity log was also used to identify the fluids. In this regards zone of possible oil accumulations is indicated by high resistivity values whereas water zones have low resistivities.
4) *Bulk Volume Of Water:* Bulk Volume of Water is Fraction of the rock volume that is occupied by water. BVW of the hydrocarbon-bearing zone is calculated using the equation

$$K = \left[\frac{250\times\Phi^{3}}{S_{wir}}\right]^{2}$$

Where:
BVW = bulk volume of water.
Sw = water saturation.
∅a = average porosity.

5) *Cutt-Off Factor:* Cut off factor is used to identify the reservoir and non-reservoir zones, encountered in a well. For a reservoir the following cut off factor criteria have been employed.

Porosity φ > 6 %,
Volume of shale Vsh < 30%,
Water saturation Sw < 50

6) *Water Saturation (SW):* Water saturation is the percentage of water which is present in the pores of a formation. Rocks and formations having high clay content stores large amount of water and thus possess high water saturation, as compared to the other having less clay content. Water saturation simply gives the relative proportions of these fluids contained in the reservoir pore spaces. Water saturation depends upon the formation resistivity factor (Fr) and resistivity of water present in the pores space of the rock.

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

Where,
n = saturation exponent
a = tortuosity factor
φ = porosity
m = cementation exponent
Rw= formation water resistivity
Rt= true formation resistivity

7) *Net/ Gross Reservoir Thickness:* The gross reservoir thickness H, was determined by looking at tops and bases of the reservoir sands across the well. The net thickness which is the thickness of the reservoir was determined by defining basis for non-reservoir and reservoir sands using the gamma ray log. This was carried out by drawing a shale baseline and sand baseline on the gamma ray log.

$$h = H - h_{shale}$$

$$Net/Gross = h/H$$

Where
H =Gross reservoir thickness
h =Net reservoir thickness
h_{shale} =Shale thickness

8) *Hydrocarbon Saturation:* The degree to which a formation is saturated by hydrocarbon (oil, gas) is known as hydrocarbon saturation, expressed as a percentage of pore volume.

$Sh=1-Sw$
Where,
Sw= water saturation
Sh= hydrocarbon saturation

9) *Water Resistivity:* To calculate water saturation, Sw we need the water resistivity, Rw value at formation temperature calculated from the porosity and resistivity logs within clean water zone, using the Ro method given by the following equation

$$R_w = {}^{R_o}/_{F}$$

Where,
Ro = Deep resistivity value
F= Formation Factor

10) *Formation Resistivity Factor (FRF):* Formation resistivity factor (Fr) can be quantified as the ratio of the formation's wet resistivity to the resistivity of the water (Rw) present in that formation.

Fr = Ro/Rw

Formation water resistivity (Rw) is defined as constant and therefore, changes in formation resistivity factor (Fr) will occur only with changes in the overall formation resistivity (Ro). The one way in which Ro can change in a formation with constant Rw is by changing the amount of fluid available to conduct an electrical current. This is accomplished through changes in porosity.

As porosity decreases, the amount of water available to conduct electrical current is decreased, resulting in an increase in formation resistivity (Ro). Therefore, formation resistivity factor (Fr) is inversely proportional to porosity (F).

Fr =1/φ

Changes in the complexity of the pore network that affect the conductive nature of the fluids present, and formation resistivity factor (Fr) can therefore vary with the type of reservoir. These changes are expressed by the tortuosity factor (a) and cementation exponent (m).

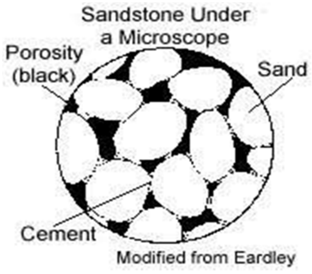
Fr =$a/\varphi m$

The formation Resistivity Factor (FRF) also called the formation factor (F) was computed using Archie's Formula

$$F = a/\Phi^m$$

Where,
a = constant related to texture, (assumed to be approximately 1 for sandstone)
m = cementation factor ($2 \leq m \geq 1.3$)
Φ = total porosity

11) *Porosity Estimation:* Porosity of reservoir is the property that tells how porous a rock is. It is also defined as a measure of the capacity of reservoir rocks to contain or store fluids. The porosity is genetically classified basing on standard sedimentologic description of reservoir rock; there are primary and secondary porosity.



Modified from Eardley

a) The Primary Porosity Types Are

- Inter Particle Porosity, in this type by which rock content was quickly lost in muds and carbonate sands through compaction and cementation respectively. This type is mostly found as siliciclastic sands.
- Intra Particle Porosity by which the porosity is made of interiors of carbonate skeletal grains.

b) The Secondary Porosity

The porosity formed after deposition leads to other couple of reservoirs types.

- Dissolution porosity type is made of carbonate dissolution and leaching. It is also called carbonate reservoirs.
- Fracture porosity which is characterized by not being voluminous.

Porosity can also be classified basing on rock morphology. There are three types of morphologies to the pore spaces which are:

- ➢ Catenary in which the pore open to more than one throat passage.
- ➢ Cul-de-sac in which the pore open to only one throat passage.
- ➢ Closed pore in which there is no connection with other pores.

The volume of space between the solid particles of the rock to the total rock volume is the porosity of that rock. The volume of space comprises all pores, cracks, inter- and intra-crystalline spaces.

$$\emptyset = \frac{Vpore}{Vbulk} = \frac{Vbulk - Vmatrix}{Vbulk} = \frac{Vbulk - (\frac{Wdry}{\rho matrix})}{Vbulk}$$

Where,
Vpore = pore volume
Vbulk = bulk rock volume
Vmatrix = volume of solid particles composing the rock matrix
Wdry = total dry weight of the rock
ρmatrix = mean density of the matrix minerals

The porosity used in this study was computed from the density log. The density log records the formation's bulk density which is the overall density of a rock including the solid matrix and the fluid enclosed in the pores.

12) *Permeability Estimation:* Permeability is a measure of the ability of a fluid to pass through its porous medium. Permeability is one of important to determine the effective reservoir. Porosity and permeability are two properties describing the reservoir rock capacity with regard to the fluid continence. Moreover, a reservoir rock can be porous without being permeable. For example, it is said to be permeable if and only if the pores "communicate". Hence for explorationists, knowing reservoir rock permeability is a key mile stone because it is important for being used to determine if it really has sufficient commercial accumulation of oil, indeed measuring it is very difficult. The measuring of permeability can differently be understood basing on two different ways. When the porous medium is completely saturated by a single fluid, the permeability will be described absolute, become described as effective permeability when its porous medium is occupied by more than one fluid.

Three types of Permeability:

a) Absolute permeability is an ability to flow fluid through a permeable rock when only one type of fluid is in the rock pore spaces. The absolute permeability is used to determine relative permeability of fluids flowing simultaneously in a reservoir.
b) Effective permeability is the permeability of a particular phase in the interconnected pore space of the rock.
c) Relative permeability is the ratio of effective permeability of a particular fluid at a particular saturation to absolute permeability of that fluid at total saturation.

Various models have been proposed over the years relating the permeability of a rock to its porosity, Φ, and irreducible water saturation (S_{wir}) as obtainable from wire line logs.

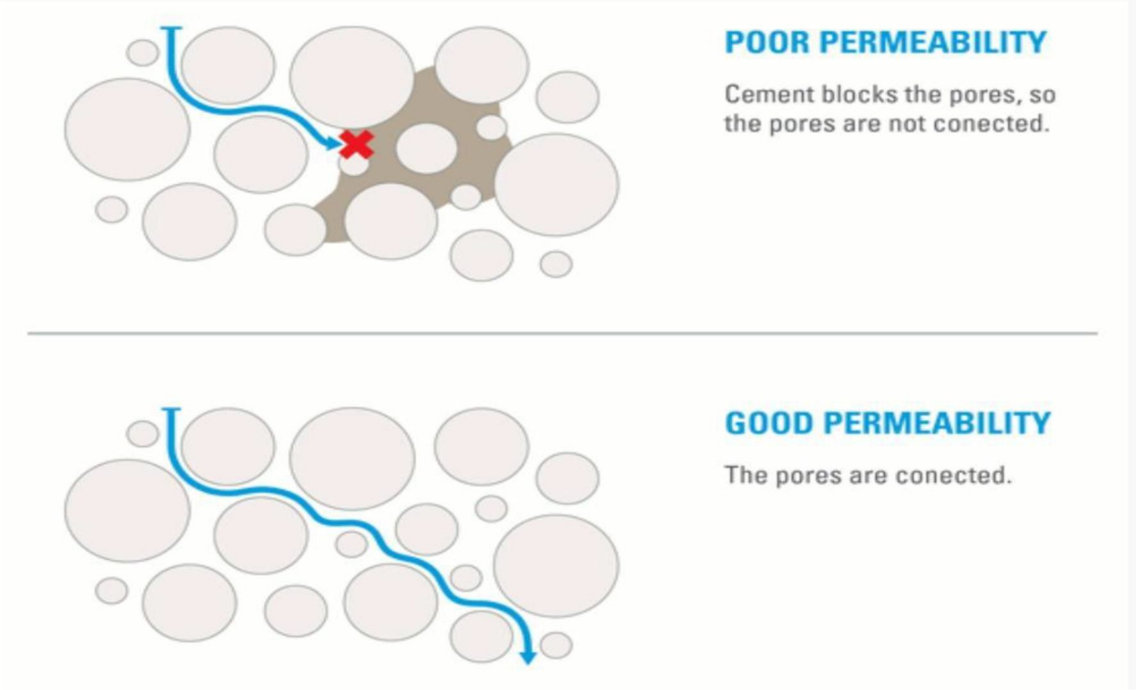
$$K = \left[\frac{250 \times \Phi^3}{S_{wir}}\right]^2$$

Where,
S_{wir}= Irreducible water saturation
Φ = Total porosity

The irreducible water saturation may be derived using the Schlumberger approach. In the zone of irreducible water saturation, the hydrocarbon produced is water free. Irreducible water saturation is defined mathematically as

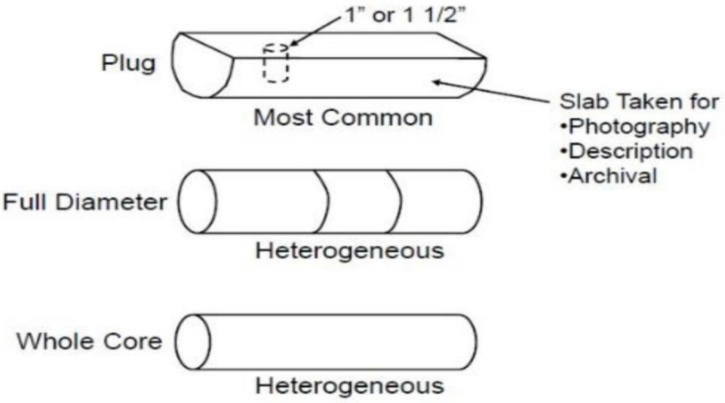
$$S_{wtr} = \left({}^{F}/_{2000}\right)^{\frac{1}{2}}$$

Where,
F= Formation factor.



V. CORE CLEANING

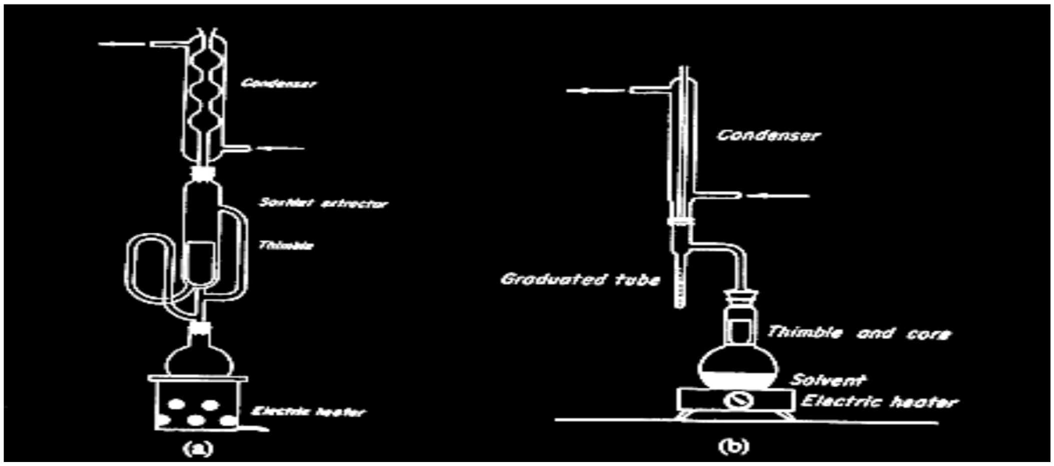
Porosity, permeability, grain density, and mineralogy of reservoir rocks are important elements in a reservoir description. We can estimate these properties from well logs or measure them from rock samples in the laboratory. The rock samples are obtained by cutting a piece of rock from the well bore; the process is called coring.



A. Core Cleaning Methods

Before measuring porosity and permeability, the core samples must be cleaned of residual fluids using solvents, then thoroughly dried. There are numerous lab techniques available to do this. Most methods also provide the oil and water saturation of the core samples on an "as-received" basis. The number of cycles or amount of solvent which must be used depends on the nature of the hydrocarbons being removed and the solvent used. Often, more than one solvent must be used to clean a sample. The solvents selected must not react with the minerals in the core. Toluene and benzene are most frequently used to remove oil and methanol and water is used to remove salt from interstitial or filtrate water. The cleaning procedures used are specifically important in special core analysis tests, as the cleaning itself may change wettability. The core sample is dried to remove connate water from the pores, or to remove solvents used in cleaning the cores. When hydratable minerals are present, the drying procedure is critical since interstitial water must be removed without mineral alteration. Drying is commonly performed in a regular oven or a vacuum oven at temperatures between 500C to 1050C. If problems with clay are expected, drying the samples at 600C and 40 % relative humidity will not damage the samples.

1) *Direct Injection Of Solvent:* The solvent is injected into the sample in a continuous process. The sample is held in a rubber sleeve thus forcing the flow to be uniaxial.
2) *Centrifuge Flushing:* A centrifuge which has been fitted with a special head sprays warm solvent onto the sample. The centrifugal force then moves the solvent through the sample. The used solvent can be collected and recycled.
3) *Gas Driven Extraction:* The sample is placed in a pressurized atmosphere of solvent containing dissolved gas. The solvent fills the pores of sample. When the pressure is decreased, the gas comes out of solution expands, and drives fluids out of the rock pore space. This process can be repeated as many times as necessary.
4) *Soxhlet Extraction:* A Soxhlet extraction apparatus is the most common method for cleaning samples, and is routinely used by most laboratories. As shown in the illustration, toluene is brought to a slow boil in a Pyrex flask (Figure-a); its vapors move upwards and the core becomes engulfed in the toluene vapors at approximately 1100C. Eventually, water within the core sample in the thimble will be vaporized. The toluene and water vapors enter the inner chamber of the condenser, the cold water circulating about the inner chamber condenses both vapors to immiscible liquids. Recondensed toluene together with liquid water fall from the base of the condenser onto the core sample in the thimble; the toluene soaks the core sample and dissolves any oil with which it come into contact. When the liquid level within the Soxhlet tube reaches the top of the siphon tube arrangement, the liquids within the Soxhlet tube are automatically emptied by a siphon effect and flow into the boiling flask. The toluene is then ready to start another cycle. A complete extraction may take several days to several weeks in the case of low API gravity crude or presence of heavy residual hydrocarbon deposit within the core. Low permeability rock may also require a long extraction time.
5) *Dean-Stark Distillation-Extraction:* The Dean-Stark distillation provides a direct determination of water content. The oil and water area extracted by dripping a solvent, usually toluene or a mixture of acetone and chloroform, over the plug samples. In this method, the water and solvent are vaporized, recondensed in a cooled tube in the top of the apparatus and the water is collected in a calibrated chamber (Figure-b). The solvent overflows and drips back over the samples. The oil removed from the samples remains in solution in the solvent. Oil content is calculated by the difference between the weight of water recovered and the total weight loss after extraction and drying.



B. Solvents Used For Core Cleaning

The core cleaning process is said to be successful when all the contaminants are removed from the surface of the rock leaving it strongly water- wet. Core cleaning is mostly a trial and error process where the selection of the best solvents to be used greatly depends on the experience with the particular rocks. It has been shown that mixtures of solvents work better than the single solvents. Common solvent mixtures are Chloroform/ Methanol, Toluene/ Methanol, Toluene/ Ethanol, Benzene and Carbon disulphide among others. Some mixtures work better for different types of rocks and fluids. Sandstones are known to have a surface of acid type while limestones have a surface of basic type. Because of the surface types of this rock surfaces. Acidic solvents tend to clean better the sandstones while basic solvents tend to clean better the limestones.

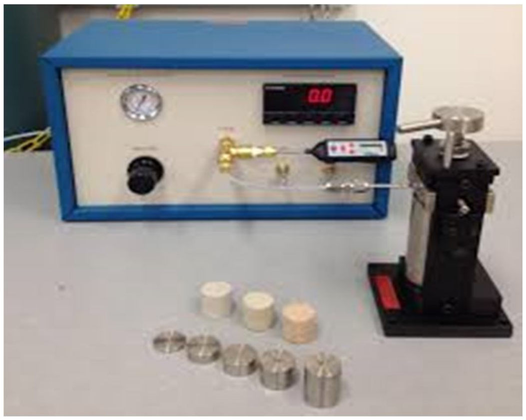
VI. POROSITY ESTIMATION

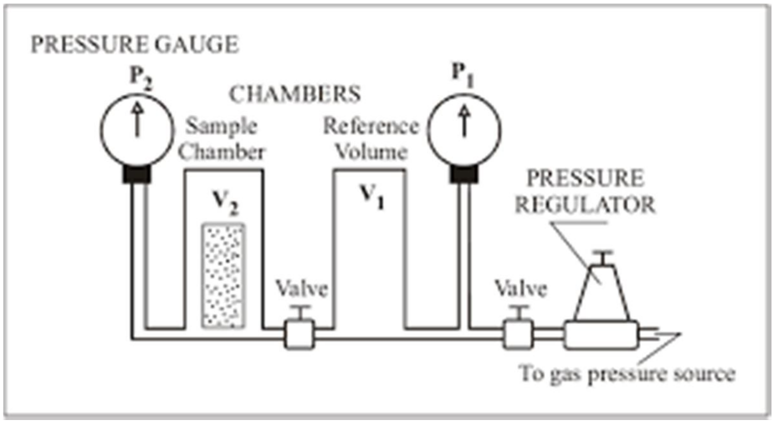
A. Helium Porosimeter

Helium Porosimeter is utilized to measure porosity of core samples taken from petroleum reservoirs, at ambient conditions. These measurements must be known for an intelligent evaluation or engineering functions preformed on the reservoir. All the methods measuring pore volume yield effective porosity.

The methods are based on either the extraction of a fluid from the rock or the introduction of a fluid into the pore spaces of the rock One of the most used methods is the helium technique, which employs Boyle's law.

He**P** is a Helium Porosimeter for Grain volume determination on samples (standard, irregular or coated) based on Boyle-Mariotte's law. Sample is set in matrix cup; pore volume is deducted from bulk volume. Measurement system is computer operated





The Helium gas expansion porosimeter enables the determination of a sample's (1" or 1.5" diameter) grain and pore volume via an isothermal helium expansion and the application O'Boyle's law and Charles' law. Subsequently, porosity and grain density can be calculated. A provided excel template facilitates the computation of these parameters as well as calibration.

The grain density and porosity are measured on cleaned and dried plugs by a helium porosimeter. The Helium-porosimeter measures the grain volume Vg of the sample. The empty sample container of the porosimeter has a volume VS before the sample is inserted. A reference volume Vr is filled by helium and the pressure Pr is recorded. The gas is expanded from the reference volume to the sample container and the resulting pressure PX is recorded.

The grain volume is determined by applying Boyles low:

$$PIVI = P2V2 \text{ or } Pr*Vr = P*(Vr+Vs-Vg).$$

For helium porosimeter, effective porosity is determined by first placing the specimen into a steel chamber (known volume) of the Boyle's law double-celled helium porosimeter (Loman et at 1993). Helium is then allowed to isothermally expand into the chamber from a reservoir of known volume and pressure until equilibrium pressure is reached (20-60min). The grain volume can be calculated from measurement of the new gas pressure. The bulk volume of the specimen is determined by immersion of the specimen in mercury. Or Mathematically.

$$\emptyset he = (Vb - Vg)/Vb$$

Where, $\emptyset he$ is the effective porosity determined by helium porosimeter, Vb is the bulk volume of the specimen determined by mercury immersion and Vs is the grain volume. Further details on the method and procedures can be found in the literature (e.g. American Petroleum Institute 1960; Luffel & Howard 1988).

As described here, this method is based on the Boyle—Mariotte law. That is a change in gas volume or gas pressure causes a commensurate change in gas pressure or volume, assuming that temperature remains constant.

B. Procedure

1) *Connect Process:* Fitting at front side of the cabinet to a suitable dry gas facility, rating up to 220 psi.
2) *Remove the Cap at the Bottom of the Transmitter:* Plug cable from the transmitter to the USB at right side of computer.

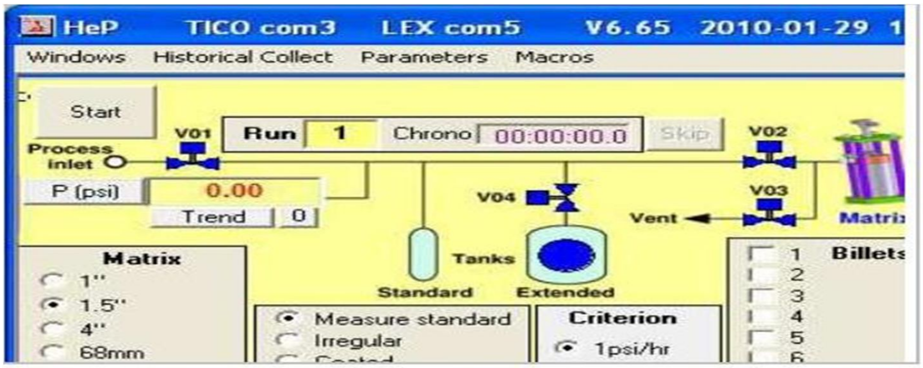
COM5 (black)	Net PC Computer
	

3) *Start:* starting appliclab, switches on the battery, operated transmitter. click on the button(psi) to toggle pressure reading with offset value. Make sure that valves can be controlled (red, green color). beside is an illustration where pressure and valve are not connected (blue color) at page 1 of this manual is displayed operational machine.

4) *Reset pressure display (offset)*

You can reset pressure sensor LEX locally as follow:

a) Press SELECT (left button) 3 times to display MANO at the bottom of the screen.
b) Press ENTER (right button).
c) ZERO is displayed at the bottom of screen.
d) Press ENTER to offset the device.



Alternatively, you can remotely offset pressure reading from AppliLab software by Click on Offset button labeled”0” on the interface. Operator is guide to operate valves in sequence.

5) *Set Reference Pressure*

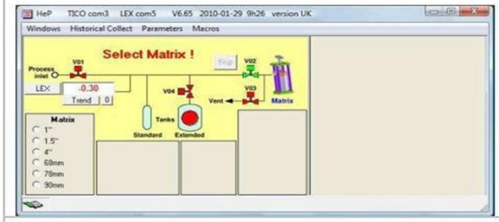
According to option, the reference pressure is 100 psig or 200 psig.

Adjust the pressure supply at the regulator of the gas facility (upstream N2 Porosimeter) to get about 120 or 220 psig (according to option). There is no need to get sharp 100 psig or sharp 200 psig. A pressure from 95 to 105 or respectively 190 to210 psig is acceptable. A relief valve built-in HeP will flow out exceeding pressure.

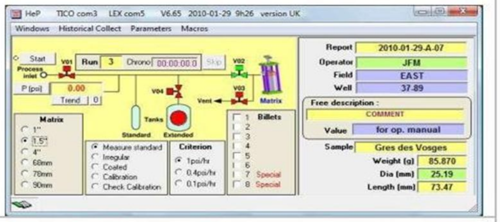
a) Open valve V01
b) Read the pressure on the cabinet
c) If the pressure reading is less than set point, turn clockwise the cabinet regulator knob to obtain the expected value and close back valve V01
d) If pressure reading is greater than set point:
e) Close valve V01
f) Open valve V02 while matrix is open to atmosphere to decrease pressure
g) Turn anti clockwise the knob
h) Close back V02
i) Open valve V01, turn clockwise the regulator knob to obtain the expected value and close back valve V01.

6) *Select Matrix in Line*

Select nominal diameter of sample in dedicated option box. Options initially hidden are now available (pictures below).



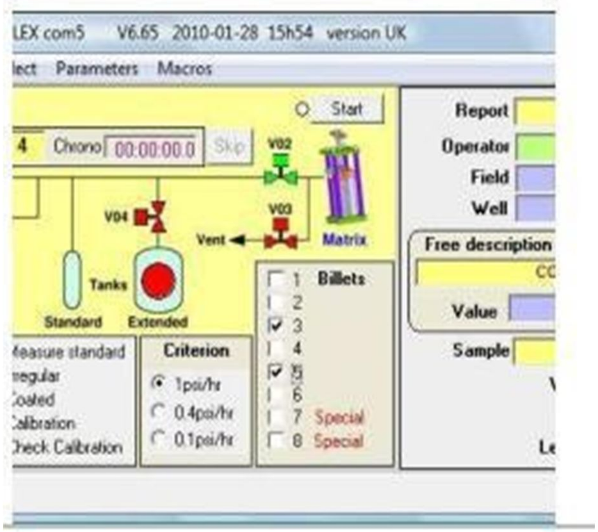
Screen before matrix selection



Report: 2010-01-29-A-07
Operator: JFM
Field: EAST
Well: 37-89
Free description : COMMENT
Value: for op. manual
Sample: Gres des Vosges
Weight (g): 85.870
Dia (mm): 25.19
Length (mm): 73.47

Screen for 1.5”matrix selected

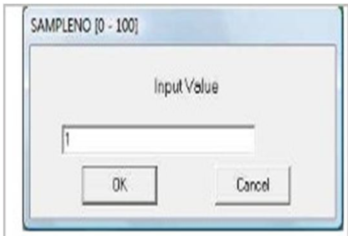
7) *Billets (calibrated discs):* Billets are used during calibration and may be used to reduce free room when small sample is loaded into matrix.



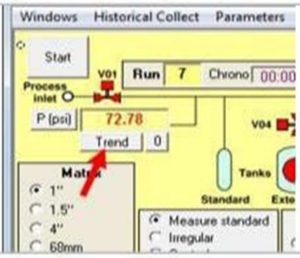
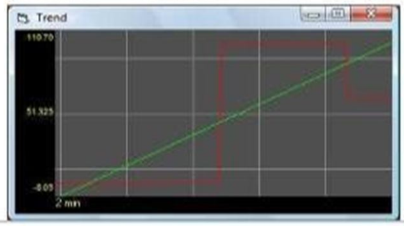
In this illustration billets loaded are No 3 and 5.

8) *Report and Template:* Template and reports files are EXCEL files with three tabs: REPORT, CALIB and PRINT. Operator is not allowed to edit manually template. Template is updated at tab CALIB by AppliLab software during calibration.

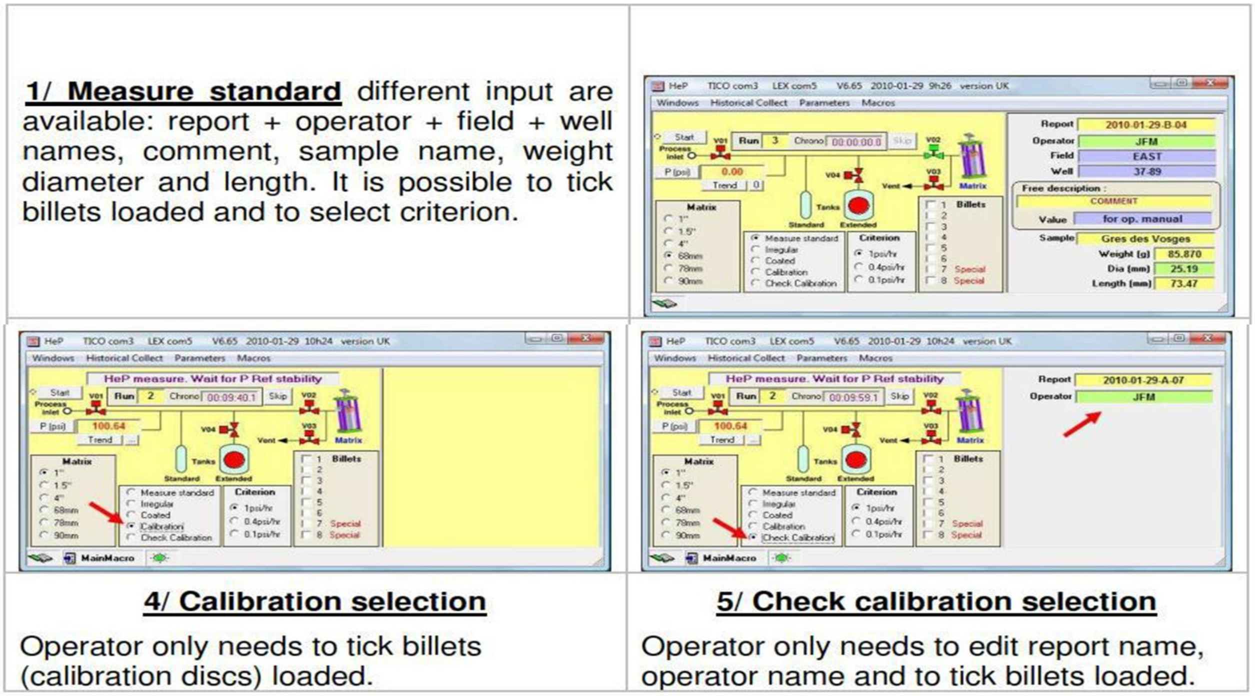
9) *Run NUMBER*

	Run number is used either during calibration (from 1 to 10) and measure (from 1 to 100). Click in the cell beside Run to input sample number (from 1 to 100). At the end of the process, AppliLab software increases automatically samples run number.

10) *Trend Facility*

	Click here to display auto range pressure trend. Click again to close trend window.
	Red line is LEX reading. Green line indicates the slope. You can move, resize the window with the mouse (or maximize) like a standard Windows.

11) *Actions*



1/ Measure standard different input are available: report + operator + field + well names, comment, sample name, weight diameter and length. It is possible to tick billets loaded and to select criterion.

Report: 2010-01-29-B-04
Operator: JFM
Field: EAST
Well: 37-89
Free description: COMMENT
Value: for op. manual
Sample: Gres des Vosges
Weight (g): 85.870
Dia (mm): 25.19
Length (mm): 73.47

HeP measure. Wait for P Ref stability

Report: 2010-01-29-A-07
Operator: JFM

4/ Calibration selection

Operator only needs to tick billets (calibration discs) loaded.

5/ Check calibration selection

Operator only needs to edit report name, operator name and to tick billets loaded.

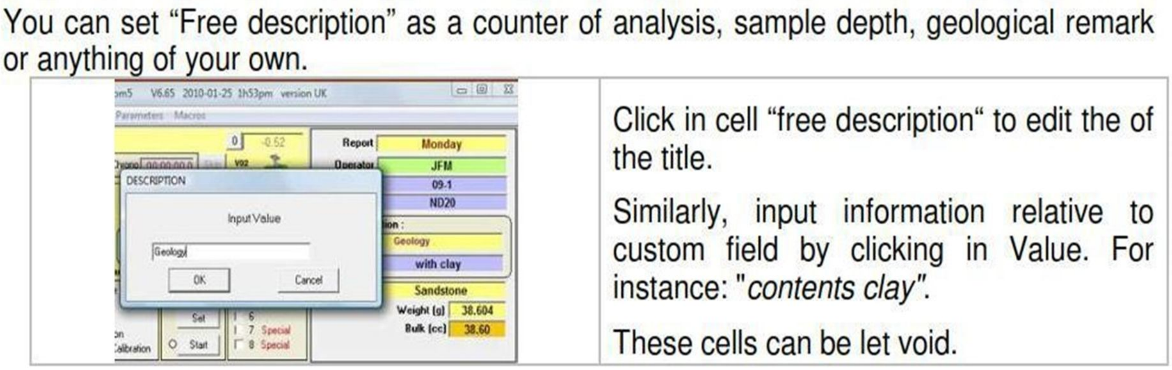
12) *Measure operation:* Remember that steady temperature is primordial to correct calibration and measure. If you touch the reference tank under pressure, you will notice a drift in the pressure reading.

a) *Loading Sample Into Matrix:* For sample of 1 or 1.5” nominal diameter we use the same matrix and a liner. Open matrix by unscrewing (anti clockwise) the top handle for about one revolution. Then remove the metal cylinder from the frame. For sample of nominal diameter 1”, drive gently sample into the liner. For sample of nominal diameter 1.5”, remove the liner then load sample into the matrix. Make sure that there are no sand particles on the top of the metal cylinder (or wipe them with the finger). Drive back the metal cylinder into its frame. Tight the matrix by rotating the top handles clockwise.

b) *Operator:* Input your name or initials. This field can be let void.

c) *Field, Well:* Input Field and Well information in dedicated cells. These fields can be let void.

d) *Free Description and Value*



You can set “Free description” as a counter of analysis, sample depth, geological remark or anything of your own.

DESCRIPTION
Input Value
Geology
OK Cancel

Report: Monday
Operator: JFM
09-1
ND20
Geology
with clay
Sandstone
Weight (g): 38.604
Bulk (cc): 38.60

Click in cell “free description“ to edit the of the title.

Similarly, input information relative to custom field by clicking in Value. For instance: "*contents clay*".

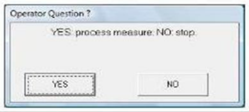
These cells can be let void.

e) *Sample:* Input sample name or experience reference, for instance sandstone07.

f) *Weight, Diameter and Length:* Input mandatory data relative to the sample. Notice that units are **grams** and **millimeters**.

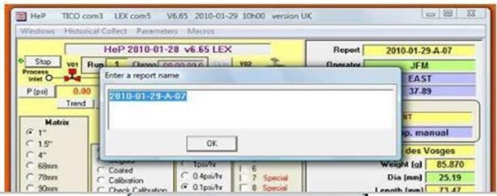
13) Common Measure Steps

13.1


Operator Question ?

YES: process measure. NO: stop.

Click on START button. This button is visible in the let top corner once you have selected the matrix (sample) nominal diameter in the check box.


Enter a report name

2010-01-29-A-07

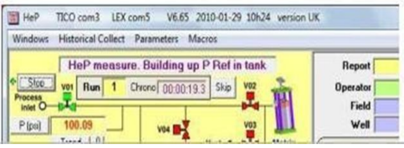
If the report name does not exist and needs to be created: a prompt ask operator for confirmation. Click OK or input a different name in this window and then click OK. If the file already exists, this prompt is not displayed.


Macro Message

Diameter is unchanged. Edit if required and then click OK

A warning message prevents you from mistake. Diameter, length, weight and run number are tested and compare to previous data. You can run several times the same experiment (sample, run number etc) after validation.

13.2



Once experiment information is validated:

Hep production series: valves are operated automatically.

Each time that a valve must be switched, a message pops up to guide operator. There is no need to the process: just follow instruction.

Operator will get information about action running by mean of message window on top of the screen. At first open system to gas net:

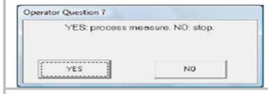
Help measure, Building up reference pressure in tank

System is waiting for stability of reference pressure ( ). SKIP button allows aborting test. Good result requires automatic stability detection.

Once stability is detected, pressure is logged in XLS file. Then, valve is operated (■) to expand gas pressure in matrix.

System is waiting for stability ( ) of expanded pressure. SKIP button allows aborting test. Good result requires automatic stability detection.

Once stability is detected, pressure is logged in XLS file. Porosity is then displayed and saved in the XLS file. Then, valve is operated (■) to vent the matrix.


Operator Question ?

YES: process measure. NO: stop.

Operator unloads the sample, and can load a new sample to process. The process is looped to the beginning.

Sample No	Sample ID	COMMENT	Sample dia (mm)	Sample Length (mm)	Bulk Vol (cc)	Dry Weight (g)	Grain Volume (cc)	Pore Volume (cc)	Grain density (g/cc)	Core Porosity (%)	Date Time of test	Pre
1	286-B	none	25.40	25.40	12.87	98.500	12.41	0.46	7.94	3.59%	25/2/10 11:35 AM	2
2	286-B	none	25.40	25.40	12.87	98.500	12.37	0.50	7.97	3.91%	25/2/10 1:53 PM	2
3	286-B	none	25.40	25.40	12.87	98.500	12.38	0.49	7.95	3.78%	25/2/10 2:03 PM	2
4	Check Calib with billets 2456	none	0.00	0.00	35.03	35.028	35.01	0.02	1.00	0.06%	25/2/10 2:10 PM	2
5	286-B_IRREGULAR	none	0.00	0.00	35.03	98.500	35.00	0.04	2.82	0.10%	25/2/10 2:21 PM	2
6	286-B_COATED	none	24.40	22.40	10.47	68.500	49.12	-38.65	1.40	-369.12%	25/2/10 2:26 PM	1
7	286-B_COATED	none	24.40	22.40	10.47	68.500	49.12	-38.65	1.40	-369.14%	25/2/10 2:27 PM	1
8												
9												
10	271-B	none	37.90	25.40	28.66	225.660	28.40	0.26	7.95	0.92%	25/2/10 2:42 PM	2
11	271-B	none	37.90	25.40	28.66	225.660	28.38	0.28	7.95	0.98%	25/2/10 2:48 PM	2
12	271-B	none	37.90	25.40	28.66	225.660	28.39	0.27	7.95	0.96%	25/2/10 2:53 PM	2
13												
14	Check Calib with billets 2456				78.94	78.936	78.92	0.02	1.00	0.02%	25/2/10 2:58 PM	2
15												

Tab REPORT

14) Shutoff procedure

a) Click **STOP** or No at prompt YES: process measure. No: stop
b) Bleed off the pressure of gas at the gas supply.
c) Switch off all the valves.
d) Quit AppliLab application.
e) Pressure display on cabinet is auto switched off.
f) Shut down Windows operating system and switch off the computer.
g) Set back the billets (calibration discs) in their case.

C. Some Point In This Experiment We Noticed, We Can Discuss Like That

The Helium Porosimeter has been performed on the principle of boyle-mariottes law& Charles law.

In this test that we did probably some factor or error effect on the accurate of the result, so we have to do this test or any test be careful and we try we don't make any error in the test otherwise the result may not accurate. Error or factor like that:

1) This device that we used in our test must contain in a room or lab which the temperature not changed because if the temperature altered of a device might the volume of air in a tool changed so the result would be some changed.
2) When we change a valve to expand or vent, we had to wait for some minute until the pressure would be stabilized.
3) We did this test more than one time for certainty about the result and maybe in any time that did the test the result changed cause man error like reading the length and diameter of sample.
4) We used nitrogen instead helium because is more available easy to handling.
5) During this experiment it could be result of **POROSITY (Negative)** because effect of (time skipped, irregular shape core, pressure).

Mercury Injected porosity meters for Oil and Helium Injected porosity meters for Gas.

VII. PERMEABILITY ESTIMATION

A. Gas Permeameter

Petroleum engineers' major job is to understand the reservoir, study and evaluate its performance. To evaluate its performance, this implies from the engineers to study the characteristics and physical behavior of a certain reservoir. There are so many properties engineers work on studying them during their journey to understand the reservoir. There are three main properties petroleum engineers firstly determine, these properties are: porosity, permeability and saturation. Petroleum engineers also work on determining other properties such as: capillary pressure, wettability, overburden pressure and much more. Knowing these properties help the engineers to take many decisions concerning the operation, equipment used and economical budget. Permeability is considered one of the most important and main properties petroleum engineers should work on determining it. Permeability is defined as the ability of the rock to transmit fluids. Due to fluid composition, there are three types of permeability. Absolute permeability is the permeability measurement of a single non-reactive fluid flowing laminarly. Effective permeability is the permeability measurement of a flowing fluid in the presence of other immiscible fluids. Relative permeability is defined as the ratio of the effective permeability to the absolute permeability (Schlumberger, n.d.). Permeability is one of the top most properties that engineers work on determining it because it helps them in knowing if they are dealing with a good or bad reservoir. As permeability increases, the ability to extract oil from the reservoir become much easier. Permeability is measured in milli-darcies or darcies (1 Darcy is equivalent to 10-12 m). It was defined by the French scientist Henry Darcy, who was able to prove the mathematics of the heat transfer can describe the fluid flow in a certain porous medium (Schlumberger, n.d.). As permeability increases, the flow rate of the flowing fluid increases according to Henry Darcy.

This indicated that the flow rate is directly proportional to the permeability. This relationship can be clarified from Darcy's equation that is used to determine the liquid's permeability under steady state conditions of laminar flow of the liquid (EQ (1.1)). EQ (1.1) is used only for incompressible liquids. Gas is considered as a compressible fluid. This means that the compressibility factor of the gas should be taken in to consideration when doing the calculations for the gas permeability. In addition to, the gas flows in the direction of the downstream of the core sample.

This leads to a decrease in the pressure and an increase in the velocity because of the expansion of gas. EQ (1.2) is used to calculate gas permeability under steady state and isothermal conditions in a porous medium (Mahfoud, n.d.). EQ (1.2) can be reduced if it satisfies the following conditions. If the pressure drop and the mean core pressure are equal, and the mean temperature and base temperature are equal.

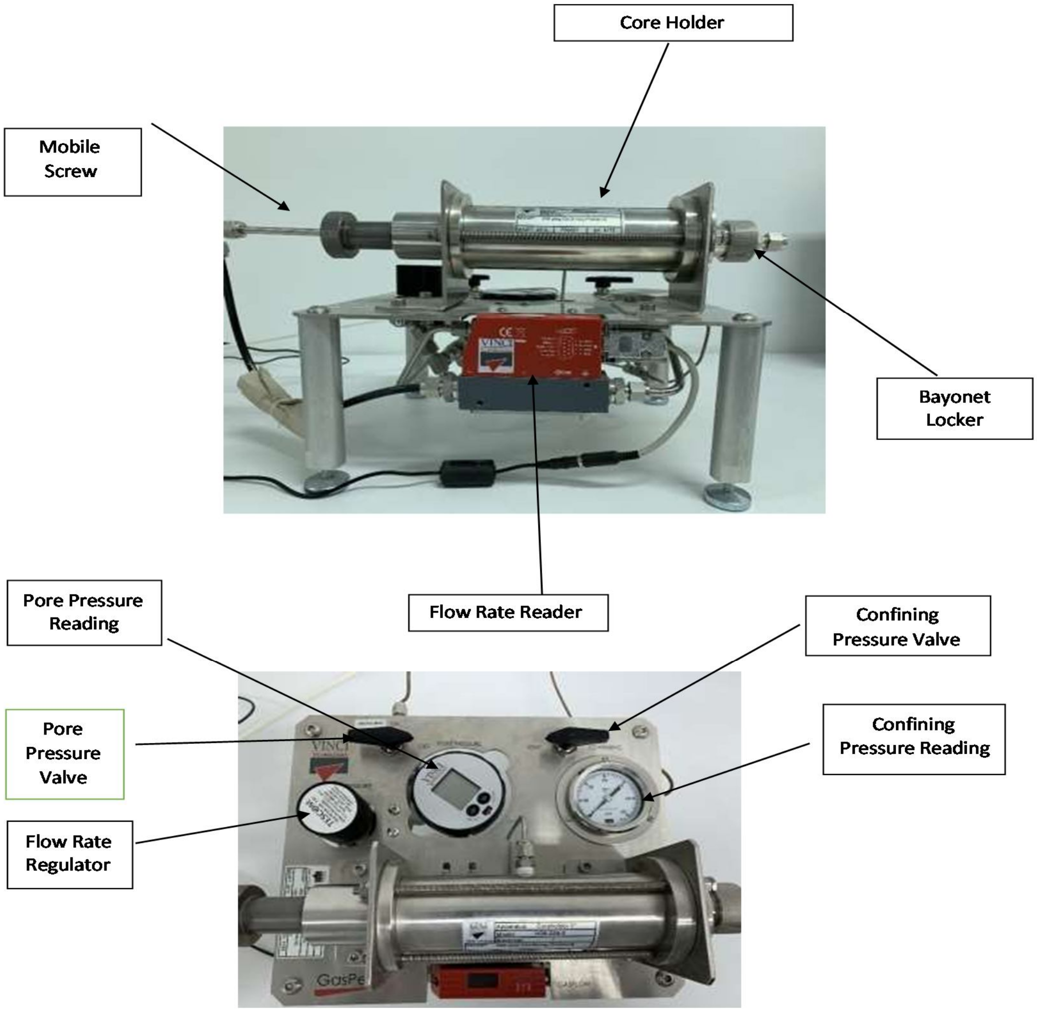
New expression for Darcy’s law (EQ (1.3)) can be introduced if it satisfies the following conditions. Klingenberg effect also have a great influence on affecting the permeability in a certain rock. It states that the permeability of the gas as the flowing fluid differs from the permeability of the liquid as the flowing fluid. This is due to the gas slippage that takes place on the grain surface of the rock, which leads to an increase in the flow rate of the gas at a given pressure difference. EQ (1.4) account for Klingenberg effect on the permeability (Mahfoud, n.d.).

Gas permeameter is the experiment applied to calculate the absolute permeability. It measures the flow rate and pressure drop during the experiment. During the experiment Darcy’s law is introduced to calculate the permeability.

Darcy’s Law Formula

$$Q = \frac{-kA(P_b - P_a)}{\mu L}$$

Q – total discharge in m^3/s
k – soil coefficient of permeability in m^2
A – cross sectional area of flow in m^2
P_b – initial pressure in Pa
P_a – final pressure in Pa
μ – viscocity in Pa
L – length in m



The gas permeameter is a device that is used to measure the permeability of a core sample with 1 to 1.5-inch diameter. The core sample is placed inside the rubber sleeve; the rubber sleeve is placed inside the core holder. At a constant flow rate, nitrogen gas is forced to the tested core sample.

The pressure difference across the core sample is measured and recorded. The flow rate is also recorded with calibrated flow meters. Using nitrogen property table, viscosity can be easily determined (Olite, n.d.). Darcy's law is introduced to the experiment in order to calculate the permeability of the core sample. It consists of many parts; the following parts are:

1) Mobile Screw: Its main role is to adjust the core sample's position under the rubber sleeve that is placed inside the core holder.
2) Pore Pressure Reading: Supply the person applying the experiment by the reading of the pore pressure.
3) Confining Pressure Reading: Supply the person applying the experiment by the reading of the confining pressure.
4) Bayonet Locker: It consists of two lockers in order to prevent losing. It firmly holds the ends of the piston.
5) Flow Rate Reading: Supply the person applying the experiment with the reading of the flow rate of the fluid injected.
6) Core Holder: It is used to place the core sample inside it, in order to apply the experiment. It has a rubber sleeve inside it.
7) Confining Pressure Valve: Opened if the person applying the experiment wants to supply the apparatus with the gas.
8) Pore Pressure Valve: It is used to supply the core sample and inject it with gas, in order to take measurements for the pore volume of the core sample.
9) Flow Rate Regulator: It is used to regulate the flow rate of the gas in the system. The flow rate increase when the regulator is moved in the clock wise direction. Moving the regulator in an anti-clock wise direction leads to decrease in the flow rate of the gas.

Nitrogen Supply Tank. It is used to supply the system with nitrogen gas. Nitrogen gas is forced through the core sample, and the difference in pressure is determined, in order to measure the permeability of the core sample. In addition to, flow rate of nitrogen is measured.

Nitrogen Supply Tank.

Air Supply tank. To supply air to the rubber sleeve. So that the core sample will be placed well. Placing the core sample in a proper way under the rubber sleeve will lead to an accurate calculations and results

Air Supply Tank.

B. Procedure

1) Use digital caliper in order to take the dimensions of the core sample.
2) Record the dimensions and return the digital caliper back to its place.
3) Open the double clock bayonet locker.
4) Put the core sample inside the chamber.
5) Place the core sample under the rubber sleeve by adjusting the location of the mobile screw.
6) Close the chamber.
7) Check if the pore pressure valve is fully closed.
8) Check if the air confining pressure is on vent position.
9) Check the confining pressure reading, pore pressure reading and flow rate reading.
10) Open air and nitrogen supply valves, in order to supply the system with both gases.
11) Open confining pressure valve to the confining direction, to let the gases enter the system. (Range of the confining pressure reading must be between 350 psia and 400 psia.
12) Open the pore pressure valve. (Pore pressure un-stability can be easily determined, because the pore pressure increase at first then decreases).
13) Record the measurements of both the pore pressure and the flow rate.
14) Use pressure regulator to take different measurements of pressures and flow rates.
15) After recording the measurements, close the nitrogen supply valve.
16) Close the pore pressure valve.
17) Close air supply valve.
18) Close the confining pressure valve, in order to vent the system (Confining pressure, pore pressure and flow rate reading should return to their initial readings).
19) Open the chamber.
20) Take out the tested core sample.
21) Clean well the tested core sample.
22) Return all the used equipment back to its original place.

C. Discussion

Flow properties that describes permeability does not only depend on the lithology, it also depends on the chemistry and composition of the flowing fluid. Minerals found in the rocks may also affect the permeability. Clay and other minerals are sensitive and can be affected by the pore fluid. If a pore fluid is involved to the production operation and the fluid is incompatible, this will lead to a change form to the minerals found in the rock. These minerals may partially or completely block the pore spaces, which will lead to a decrease in the permeability. The decrease in the salinity of the pore fluid will lead to the expansion of the clay in the pore spaces, which will plug these spaces and decrease permeability. This is due to an increase in the effective pressure caused by these minerals.

This increase in effective pressure, will decrease the pore spaces and lower the permeability. At low effective pressures, tendency of permeability to change with pressure is great. Moreover, in rocks where the flow of the fluid is controlled by fractures, pressure dependence is very strong. This behavior can also be indicated in rocks that are poorly consolidated.

Darcy’s law states that the permeability and the pressure are inversely proportional, which can be seen from the equations he proved. Permeability is measure at a constant effective pressure. This increase in pressure will lead to some changes in the properties of the rock. So, it will compress the pore spaces and will close fracture, which will lead to a decrease in the permeability of the rock.

Rock fabric is the factor that controls the change in the magnitude of the permeability. The drop in permeability can be huge if dealing with weak and unconsolidated rocks, because these rocks have the tendency to collapse easily and decrease permeability. The pressure dependence decreases as the rock become more consolidated. If dealing with tight rocks and fractures are introduced, then an increase in the pressure difference will be observed, since fractures have the ability to dominate the flowing fluid.

As a result, permeability value is a statistical parameter that expresses the total value of several permeability values of several pore channels that are composed of different size.

Nitrogen is the gas used in order to apply the experiment, because nitrogen gas doesn’t cause any retardancies to the flow. This will greatly affect the permeability by increasing its value. This due to the molecules of the nitrogen gas that slip on the grain surface of the core sample.

VIII. TOTAL ORGANIC CARBON ESTIMATION

A. Rock Eval Pyrolysis

Pyrolysis is the decomposition of organic matter by heating in the absence of oxygen. Organic geochemists use pyrolysis to measure richness and maturity of potential source rocks. In a pyrolysis analysis, the organic content is pyrolyzed in the absence of oxygen, then combusted. The amount of hydrocarbons and carbon dioxide released is measured. The most widely used pyrolysis technique is Rock-Eval.

In Rock-Eval pyrolysis, a sample is placed in a vessel and is progressively heated to 550°C under an inert atmosphere. During the analysis, the hydrocarbons already present in the sample are volatized at a moderate temperature. The amount of hydrocarbons are measured and recorded as a peak known as S1.

Next pyrolyzed is the kerogen present in the sample, which generates hydrocarbons and hydrocarbon-like compounds (recorded as the S2 peak), CO_2, and water. The CO_2 generated is recorded as the S3 peak. Residual carbon is also measured and is recorded as S4.

Rock Eval pyrolysis is used to identify the type and maturity of organic matter and to detect petroleum potential in sediments. Rock Eval pyrolysis is done using the Delsi-Nermag Rock Eval II Plus TOC module. Samples chosen to be measured on the Rock Eval are usually subsampled from the freeze-dried material previously crushed for analyses on the coulometer and CNS.

The Rock Eval (RE) pyrolysis method consists of a programmed temperature heating (in a pyrolysis oven) in an inert atmosphere (helium) of a small sample (~100 mg) to quantitatively and selectively determine (1) the free hydrocarbons contained in the sample and (2) the hydrocarbon- and oxygen-containing compounds (CO_2) that are volatilized during the cracking of the unextractable organic matter in the sample (kerogen).

The pyrolysis oven temperature program is as follows: for 3 min, the oven is kept isothermally at 300°C and the free hydrocarbons are volatilized and measured as the S_1 peak (detected by FID). The temperature is then increased from 300° to 550°C (at 25°C/min). This is the phase of volatilization of the very heavy hydrocarbons compounds ($>C_{40}$) as well as the cracking of nonvolatile organic matter. The hydrocarbons released from this thermal cracking are measured as the S_2 peak (by FID). The temperature at which S_2 reaches its maximum depends on the nature and maturity of the kerogen and is called T_{max}. The CO_2 issued from kerogen cracking is trapped in the 300°-390°C range. The trap is heated, and CO_2 is released and detected on a TCD during the cooling of the pyrolysis oven (S_3 peak).

In summary, the four basic parameters obtained by pyrolysis are as follows:

S_1 = the amount of free hydrocarbons (gas and oil) in the sample (in milligrams of hydrocarbon per gram of rock). If S_1 >1 mg/g, it may be indicative of an oil show. S_1 normally increases with depth. Contamination of samples by drilling fluids and mud can give an abnormally high value for S_1.

S_2 = the amount of hydrocarbons generated through thermal cracking of nonvolatile organic matter. S_2 is an indication of the quantity of hydrocarbons that the rock has the potential of producing should burial and maturation continue. This parameter normally decreases with burial depths >1 km.

S_3 = the amount of CO_2 (in milligrams CO_2 per gram of rock) produced during pyrolysis of kerogen. S_3 is an indication of the amount of oxygen in the kerogen and is used to calculate the oxygen index (see below). Contamination of the samples should be suspected if abnormally high S_3 values are obtained. High concentrations of carbonates that break down at lower temperatures than 390°C will also cause higher S_3 values than expected.

T_{max} = the temperature at which the maximum release of hydrocarbons from cracking of kerogen occurs during pyrolysis (top of S_2 peak). T_{max} is an indication of the stage of maturation of the organic matter.

The RE II apparatus can also be used to determine the TOC of the sample by oxidizing (in an oxidation oven kept at 600°C) the organic matter remaining in the sample after pyrolysis (residual organic carbon). The TOC is then determined by adding the residual organic carbon detected to the pyrolyzed organic carbon, which in turn is measured from the hydrocarbon compounds issuing from pyrolysis. The type and maturity of organic matter in petroleum source rocks can be characterized from Rock Eval pyrolysis data using the following parameters:

HI = hydrogen index (HI = [100 x S_2]/TOC). HI is a parameter used to characterize the origin of organic matter. Marine organisms and algae, in general, are composed of lipid- and protein-rich organic matter, where the ratio of H to C is higher than in the carbohydrate-rich constituents of land plants. HI typically ranges from ~100 to 600 in geological samples.

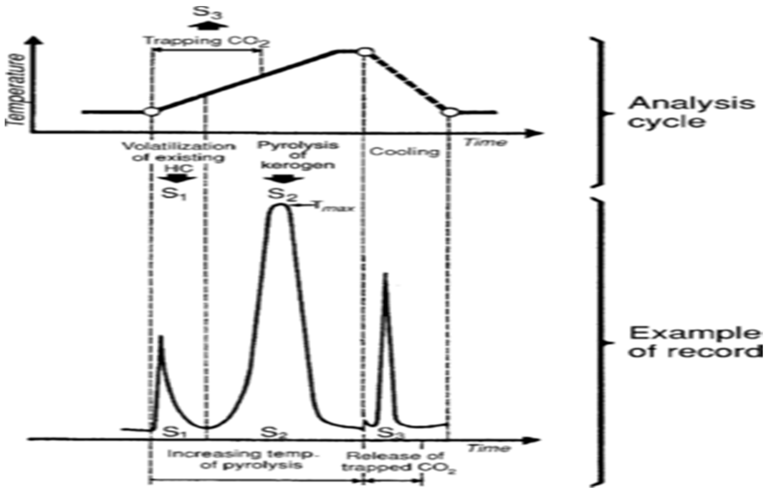
OI = oxygen index (OI = [100 x S_3]/TOC). OI is a parameter that correlates with the ratio of O to C, which is high for polysaccharide-rich remains of land plants and inert organic material (residual organic matter) encountered as background in marine sediments. OI values range from near 0 to ~150.

PI = production index (PI = S_1/ [S_1 + S_2]). PI is used to characterize the evolution level of the organic matter.

PC = pyrolyzable carbon (PC = 0.083 x [S_1 + S_2]). PC corresponds to carbon content of hydrocarbons volatilized and pyrolyzed during the analysis.

Maturation of the organic matter can be estimated by (1) the location of HI and OI and (2) T_{max} range. T_{max} = 400°-430°C represents immature organic matter; T_{max} = 435°-450°C represents mature or oil zone; T_{max} > 450°C represents the over mature zone.

Rock Eval pyrolysis is not normally used to make real-time drilling decisions because of the lengthy sample preparation, running, and interpretation time.



Peak	Is a measurement of…	Comment
S1 mg Hc/g rock	The free hydrocarbons present in the sample before the analysis	Can be thought of as a residual hydrocarbon phase. When S1 is large relative to S2, an alternative source such as migrated hydrocarbons or contamination should be suspected
S2 mg Hc/g rock	The volume of hydrocarbons that formed during thermal pyrolysis of the sample	Used to estimate the remaining hydrocarbon generating potential of the sample
S3 mg Co2/g rock	The CO_2 yield during thermal breakdown of kerogen	Most prevalent in calcareous source rocks.
S4 mg carbon/g rock	The residual carbon content of the sample	Residual carbon content of sample has little or no potential to generate hydrocarbons due to a lack of hydrogen and the chemical structure of the molecule

B. Calculation

The percent **total organic carbon (TOC)** is actually a value that is calculated, not measured directly, using the following formula.

$$\%\mathrm{TOC} = [0.082(\mathrm{S1}+\mathrm{S2}) + \mathrm{S4}]/10$$

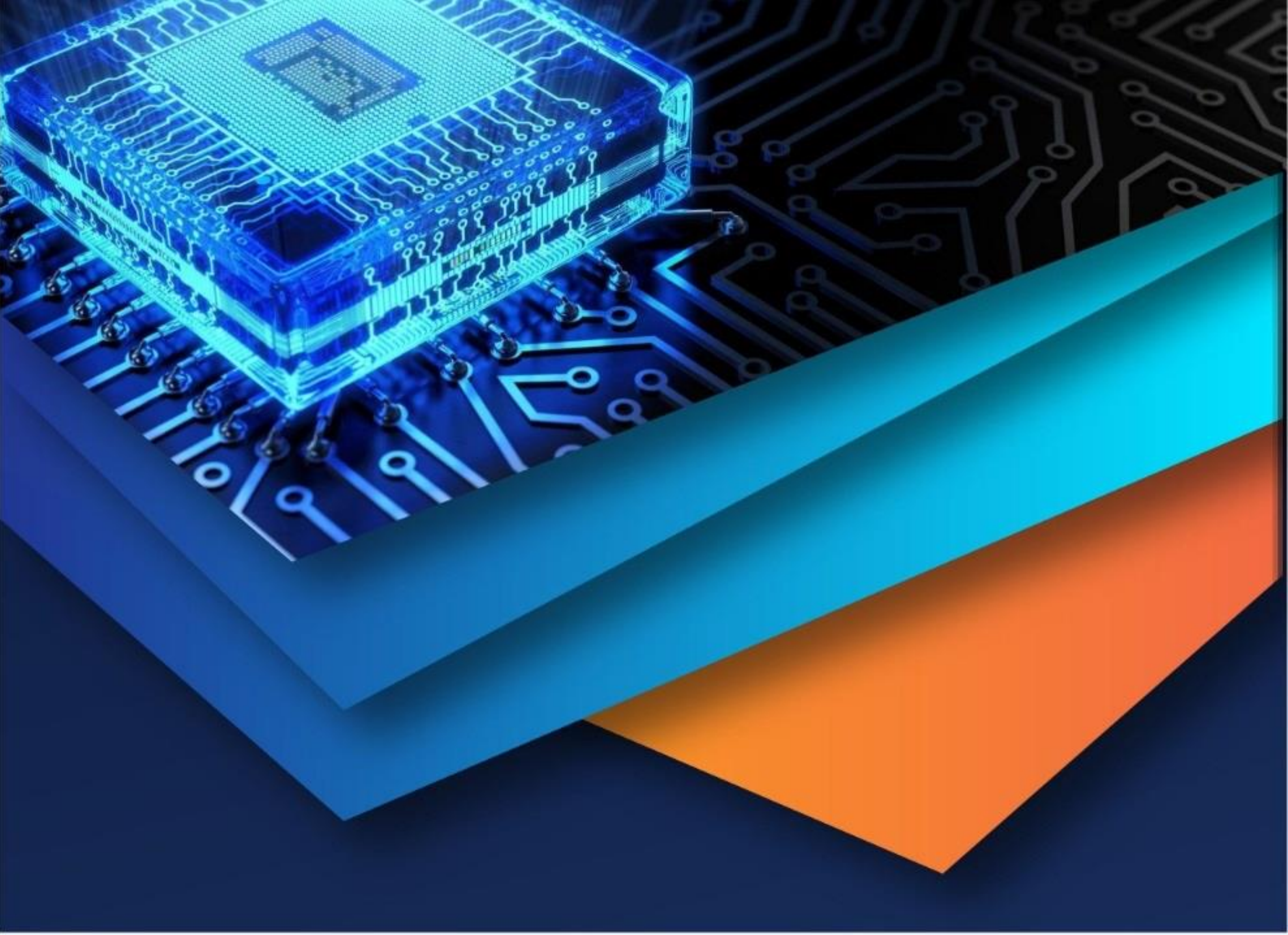
Units are usually given as wt % organic carbon per weight of dry rock (milligrams hydrocarbon per gram of rock).

IX. CONCLUSION

After the completion of our project internship training, we had been exposed to a Geologist and Chemist working life. Throughout our internship, we could understand more about the definition of Geology and Chemistry and prepare ourselves to become a responsible and innovative petroleum engineers in future. Along our training period, we realize that observation is a main element to find out the root cause of a problem. Not only for our academics but daily activities too. During our internship, we cooperate with our colleagues and mentors. Moreover, the internship training indirectly helps us to learn independently, discipline ourselves, and be considerate/patient, self-trust, take initiative and the ability to solve problems. Besides, our communication skills are improved when communicating with others. During our training period, we have received criticism and advice from engineers and technicians, when mistakes were made. However, those advices are useful guidance for us to change ourselves and avoid making the same mistakes again. Apart from that, we had also developed our practical skills through various analyses that We had done.

REFERENCES

[1] Al Mossawy M. (2019). A Simple Approach to Identify the Proper Relative Permeability Model. IOP Conf. Ser.: Mater. Sci. Eng. 495 012074.doi:10.1088/1757-899X/495/1/012074.
[2] Petro Wiki (n.d). PEH: Single Phase Permeability. Retrieved from: https://petrowiki.org/PEH:Single-Phase_Permeability#Petrologic_Controls.
[3] Schlumberger (n.d). The Oilfield Glossary: defining and Determining Permeability. Retrieved from: https://www.glossary.oilfield.slb.com/en/Terms/p/permeability.aspx
[4] Vinci Technologies (n.d.). Gas Permeability Apparatus. Retrieved from: https://www.vincitechnologies.com/productsexplo.aspx?IDM=536782&IDR=82292&IDR2=82525.
[5] Abdurahman K. (2015). Steady State Gas Permeameter. Retrieved from: https://www.slideshare.net/AppleGreen6/steady-state-gaspermeameter.
[6] Petroleum Geology of Cauvery Basin.
[7] Official Website of ONGC, SPE, APG, Google.



10.22214/IJRASET

45.98

IMPACT FACTOR: 7.129

IMPACT FACTOR: 7.429

INTERNATIONAL JOURNAL FOR RESEARCH

IN APPLIED SCIENCE & ENGINEERING TECHNOLOGY