DETERMINATION OF SOME PETROPHYSICAL PROPERTIES OF RESERVIOR ROCK: CASE STUDY OF THE LOWER SHIRE BASIN

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DISSERTATION SUBMITTED TO NDATA SCHOOL OF CLIMATE AND EARTH SCIENCES OF MALAWI UNIVERSITY OF SCINCE AND TECHNOLOGY IN PARTIAL FULFILLMENT OF THE REQUIREMENTS OF THE BACHELOR OF SCIENCE DEGREE IN PETROLEUM GEOSCIENCE

(OIL AND GAS)

Date: 29 April, 2025

DECLARATION

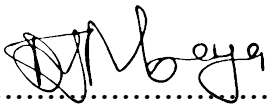
I, Amos Kambala declare that this research project presents my work and that it has never been submitted to this institution or any other institution for any academic purpose. All sources of information have been appropriately acknowledged.

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Abstract

The petrophysical calculations are crucial step in determination of properties of reservoir rock since it helps in petroleum exploration. It facilitates key decision on whether further stages of exploration can be carried out. This paper has described the determination of petrophysical properties of reservoir rock in Malawi, which was carried out on the block six of the hydrocarbon potential areas, which is lower shire basin specifically in Chiromo area. Therefore, enhancing our knowledge of reservoir rock characteristics and their role in hydrocarbon storage and flow dynamics is vital for informing exploration strategies and maximizing the potential of Block 6 in the Lower Shire Basin. The study aims at determining the porosity and permeability of reservoir rocks in the Lower Shire Basin, to understand their potential for hydrocarbon accumulation, by evaluating petrophysical properties, including, porosity, and permeability, and determining the fluid saturated in the reservoir rock. The methods used to include, fluid saturation for porosity determination, gas permeameter for permeability determination and dean-stark method for fluid saturation determination, and literature review provide more of the lithology of the area. It is discovered that Petrophysical properties, which include porosity, permeability, fluid saturation, and lithology, provide essential insights into how hydrocarbons are stored, transmitted, and produced within geological formations. Accurate assessment of these properties is fundamental for making informed decisions regarding exploration, drilling, and production strategies. The results of the study show the variations in porosity and permeability across different rock types in the Lower Shire Basin, and the fluid presence in the reservoir rock. The findings of this research contribute to the broader understanding of sedimentary basins in Malawi, and ultimately provides essential data to guide future research and resource exploitation endeavours in the region.

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CHAPTER 1: INTRODUCTION

1.0 Background of the study

The evaluation of petrophysical properties is crucial for understanding reservoir behavior and optimizing hydrocarbon recovery in the oil and gas industry. Petrophysical properties, which include porosity, permeability, fluid saturation, and lithology, provide essential insights into how hydrocarbons are stored, transmitted, and produced within geological formations (Sarah et al., 2015). Accurate assessment of these properties is fundamental for making informed decisions regarding exploration, drilling, and production strategies.

Petrophysical properties including; porosity, permeability, and mineral composition, are fundamental to the assessment of any reservoir rock's ability to store and transmit fluids. Porosity, which denotes the void spaces within rock where fluids can accumulate, is critical for determining the storage capacity of hydrocarbons. In juxtaposition, permeability describes the rock's ability to allow fluids to flow through its interconnected pore spaces, which is essential for any potential production activities (Ren et al., 2025). Understanding the interplay between these properties provides valuable insights into the viability of utilizing the Lower Shire Basin's geological formations for petroleum extraction.

In reference with the petroleum potential that has been justified by the geological, structural and sedimentary properties of the studied area, Malawi hydrocarbon potential areas are divided into six blocks. These divisions designate the hydrocarbon potential area for exploration. The first block covers the Vwaza marsh/ Chitipa in the northern region of Malawi, while the second, third and fourth block covers Lake Malawi north, central and south respectively. The Fifth block which covers lake Chilwa /lake Malombe Area and lastly, the sixth block which covers the lower shire rift. The hydrocarbon potential is rather high in the second, third and sixth block, this is because of the depth which plays a crucial role in the formation of hydrocarbons (Chisenga, 2012).

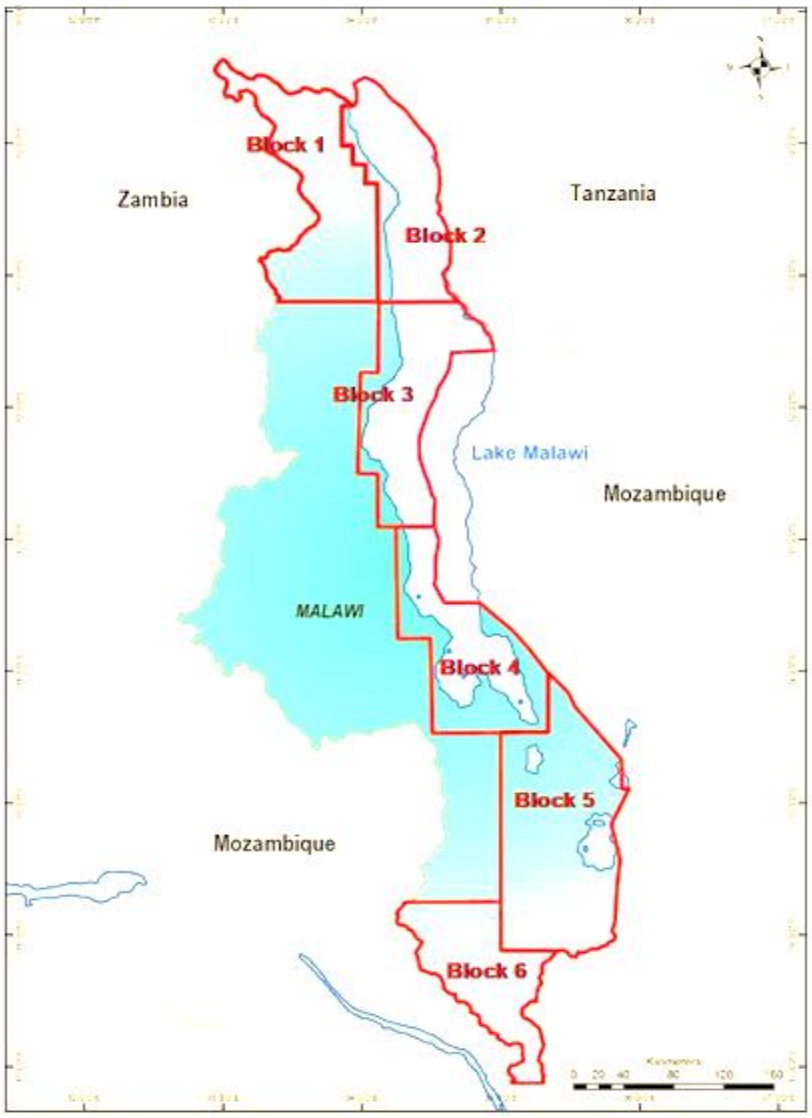


Figure 1 Malawi potential hydrocarbon blocks

The Lower Shire Basin in Malawi represents a significant geological formation that offers insights into the petrophysical properties of reservoir rocks, an area of critical importance for understanding hydrocarbon potential. Characterized by its complex stratigraphy, the basin encompasses sedimentary rock sequences that include consolidated shales, sandstones, and other lithologies from the Karroo and Cretaceous periods (Mattick, 1984).

1.1 Problem Statement

In the context of hydrocarbon exploration, Block 6 in the Lower Shire Basin presents promising opportunities for the discovery and extraction of potential hydrocarbon resources (Wyson & Malunga, 2017). This area is noted for its geological formations that could harbour significant oil and gas deposits; hence, the comprehensive assessment of its hydrocarbon potential is required to complement initial findings.

Currently, much of the research conducted in this region has primarily concentrated on the source rock characteristics, which are crucial for understanding the generation of hydrocarbons. These studies have provided valuable insights into the organic material richness and thermal maturity of the source rocks, laying a foundation for potential exploration efforts (Christopher, 2022). However, this focus on source rock alone may overlook other critical aspects necessary for a complete evaluation of the prospectivity of the basin.

One notable gap in the existing literature is the relative scarcity of research dedicated to examining the properties of reservoir rocks in Block 6. Reservoir rocks are pivotal for successful hydrocarbon production, as they determine the capacity and capability for fluids to accumulate and flow. Understanding the porosity, permeability, and structure of these reservoir rocks is essential for accurately assessing how hydrocarbons can be stored and moved within the geological formations (Rasool & Abbas, 2011). Therefore, enhancing our knowledge of reservoir rock characteristics and their role in hydrocarbon storage and flow dynamics is vital for informing exploration strategies and maximizing the potential of Block 6 in the Lower Shire Basin. By addressing this research gap, stakeholders can better evaluate the full hydrocarbon potential of the region and develop more effective strategies for exploration and production.

1.2 Objectives

1.2.1 Main Objective

To determine the porosity and permeability of reservoir rocks in the Lower Shire Basin, to understand their potential for hydrocarbon accumulation.

1.2.2 Specific Objectives

- To evaluate petrophysical properties, including, porosity, and permeability.
- To determine the fluid saturated in the reservoir rock

1.3 Research Question

1. What are the variations in porosity and permeability across different rock types in the Lower Shire Basin?
2. What is the fluids presence in the reservoir rock to be identified?

1.4 Justification

Petroleum exploration in Malawi, particularly in the Lower Shire region, holds significant economic potential. The discovery and development of hydrocarbon resources could provide a substantial boost to the national economy through the creation of jobs, the generation of revenue, and the potential to reduce energy imports.

The geological settings of the Lower Shire region are complex and not fully understood. This study will contribute to the body of knowledge by characterizing the subsurface geology, which is essential for identifying viable hydrocarbon systems.

CHAPTER 2. LITERATURE REVIEW

2.0 Introduction

This chapter discussed the approach used in this study and how the lithology relates to petrophysical properties like porosity, permeability, fluid saturations, etc.

2.1 The primary lithology of the area

Lithologies reflect different hydrodynamic conditions and sediment transporting mechanisms. As lithology controls the distribution of petrophysical properties including porosity and permeability, a good understanding of the spatial variation of lithologies is of great significance for the exploration of underground reservoirs. Initial information of subsurface lithology is typically obtained from the observation of well cores and the analysis of well logs (Ren et al., 2019). The lithology of a rock unit is a description of its physical characteristics visible at outcrop, in hand or core samples, or with low magnification microscopy. Physical characteristics include color, texture, grain size, and composition (Mcnair, 2023).

Lithology may refer to either a detailed description of these characteristics, or a summary of the gross physical character of a rock. Examples of lithologies in the second sense include sandstone, slate, basalt, or limestone. Lithology is the basis of subdividing rock sequences into individual lithostratigraphic units for the purposes of mapping and correlation between areas. Mcnair, (2023) Minerals and oil often occur in areas with certain lithologies. Therefore, explorers may use the lithologic information, including maps in exploration, i.e., target areas likely to have minerals or oil. In the petroleum industry, lithology or mud logging will help predict and calculate resources and a good area, and lithology may help show the correlation between different areas.

Lithology identification is an important task in geological work such as exploration and reservoir evaluation. In resource exploration, accurate lithology identification is the basis for reservoir characterization studies and reserve calculation, and refined lithology identification is reliable basis for determining the spatial spread of lithology and characterizing regional geology (Shi et al., 2023). In underground engineering, lithology affects construction speed and construction plans, and accurate identification of lithology is vital for preventing underground engineering disasters and improving project efficiency (Singh & Ojha, 2022).

Ren et al., (2019), proposed a new method using both logs data and captured lithology combination pattern for lithology identification. In their method, they first obtained the probability of each lithology from multiple well logs using standard artificial neural networks, and then converted the combining patterns of various lithologies observed in core or outcrop into the form of conditional probability, by using statistical theory, at last, they integrated the above conditional probabilities using a probability combination scheme, and predict lithology with the integrated joint probability. The basic workflow of

this method is illustrated in figure 2. The details of this method are illustrated in the following three subparts.

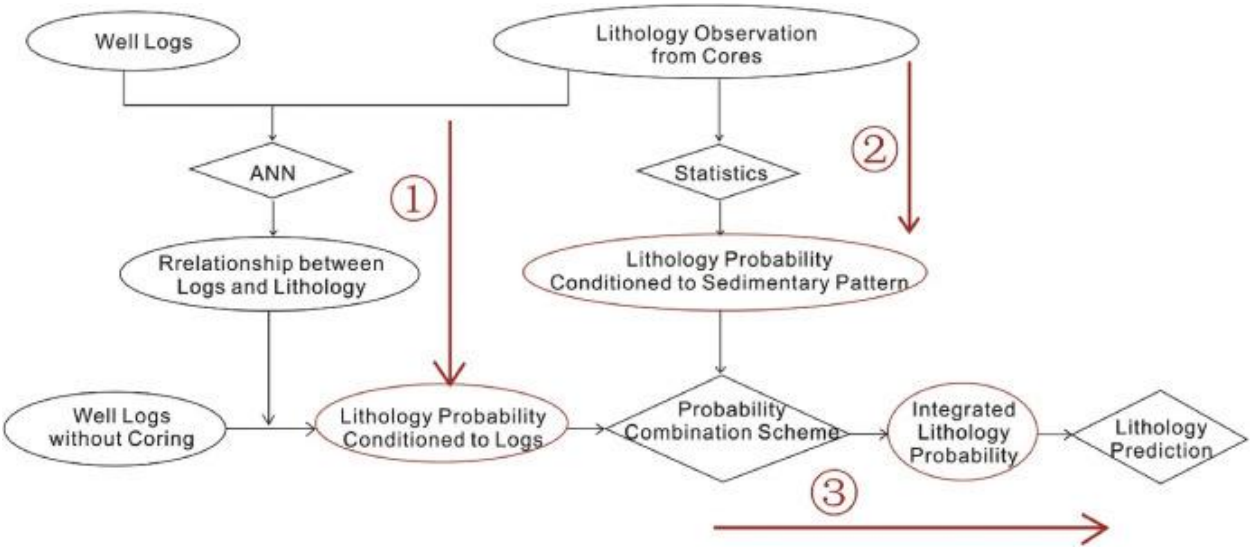


Figure 2. Flowchart illustrating the major steps of the proposed method.

There are three traditional lithology identification methods: (1) hand specimen identification, where geologists identify the lithological features based on the apparent characteristics and geological context of the rocks, (2) thin section identification, where geologists identify the lithological features by analyzing rock thin sections under a microscope, and (3) physical testing, where geologists detect and analyze the rock composition using instruments such as an X-ray diffractometer, an X-ray fluorescence spectrometer, and an infrared spectrometer (Xu et al., 2021).

2.2 Porosity of Reservoir Rocks

Porosity is a fundamental property of reservoir rocks that determines their capacity to hold hydrocarbons. It is defined by the volume of void spaces within a rock that can potentially store fluids, such as oil, gas, and water (Monicard, 1980). The study of porosity is crucial for understanding the storage and flow characteristics of petroleum reservoirs.

2.2.1 Fundamentals of Porosity

Sedimentary rocks, which are the primary reservoir rocks, consist of grains of solid matter that are more or less cemented together. The spaces between these grains, if interconnected, can contain and allow the circulation of fluids, making the rock both porous and permeable. Monicard, (1980) emphasizes the importance of pore volume,

overburden pressure, and compressibility factors in determining the porosity of reservoir rocks.

The porosity types can be also classified according to their origins of formation (Selley, 1998; Tiab & Donaldson, 2015). Primary pores indicate the pores that are formed during the time of sedimentation, as shown in Table 1. Interparticle pores are initially present in all sediments, but their sizes are quickly reduced by compaction. These interparticle porosities are physically affected by gradation of grains, grain shape, degree of cementation, amount of compaction, and packing method. By contrast, intraparticle pores are generally found within the skeletal grains, mostly in carbonate sands, diatoms.

Table 1. Classification of Porosity in Sedimentary Rocks

Time of formation	Type	Origin
Primary or depositional	Intergranular or interparticle	Sedimentation
	Intergranular or interparticle	
	Intercrystalline	Cementation
	Fenestral	
Secondary or postdepositional	Vuggy	Solution
	Moldic	
	Fracture	Tectonic, compaction dehydration, diagenesis

Secondary porosity develops in rocks after the initial sediment deposition due to geological processes like diagenesis and catagenesis. Solution porosity, including moldic and vuggy pores, is a common type of secondary porosity, particularly prevalent in carbonate reservoirs compared to sandstone reservoirs. Dolomitization and fracture porosity are also forms of secondary porosity. While fracture porosity may not significantly increase the overall porosity, it plays a crucial role in enhancing reservoir permeability by creating interconnected pathways for fluid flow (Tiab & Donaldson, 2015). Due to their large scale,

fractures are best assessed using an integrated approach combining borehole logging, seismic data, and well production history.

2.2.2 Geological Influence on Porosity

The geological setting of a petroleum reservoir significantly influences its porosity. Factors such as sediment composition, grain size distribution, and the degree of cementation play a critical role. Baruah et al., (2022) discuss how the physicochemical properties of reservoir rocks, including porosity, are vital for the extraction of hydrocarbons. They also highlight the importance of understanding the reservoir drive mechanisms to evaluate production profiles. Pores are of three morphological types: catenary, cul-de-sac, and closed, figure 3. Catenary pores are those that communicate with others by more than one throat passage. Cul-de-sac, or dead-end, pores have only one throat passage connecting with another pore. Closed pores have no communication with other pores.

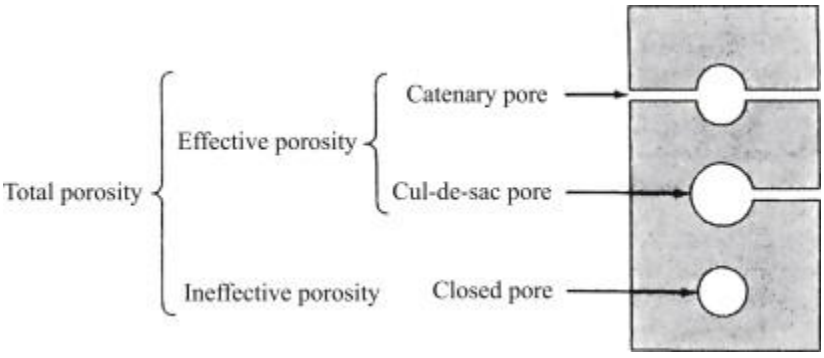


Figure 3. The three basic types of pores.

Catenary and cul-de-sac pores constitute effective porosity, in that hydrocarbons can emerge from them. In catenary pores hydrocarbons can be flushed out by a natural or artificial water drive. Cul-de-sac pores are unaffected by flushing, but may yield some oil or gas by expansion as reservoir pressure drops. Closed pores are unable to yield hydrocarbons (such oil or gas having invaded an open pore subsequently closed by compaction or cementation). The ratio of total to effective porosity is extremely important, being directly related to the permeability of a rock

2.2.3 Estimation and Evaluation of Porosity

Advanced techniques and methodologies have been developed to estimate and evaluate the porosity of reservoir rocks (Ganat, 2020). Well-logs, core analysis, and petrophysical

evaluations are among the tools used by geologists and engineers to assess porosity and other related properties (Lee et al., 2020. These methods provide insights into the distribution and connectivity of pore spaces, which are essential for predicting the behavior of hydrocarbon reservoirs.

2.3 Permeability of Reservoir Rocks

Permeability in geological terms is the measure of a rock's ability to transmit fluids through its pore network (Yang, 2017a). It is often quantified in darcies or millidarcies and is influenced by factors such as pore throat size, tortuosity, and the viscosity of the fluid. The seminal work of Darcy established the foundational law governing fluid flow through porous media, which is still applied in reservoir engineering today (Yang, 2017). Understanding this can help to know whether the fluid will flow easily during production.

The permeability of reservoir rocks can be affected by several geological processes, including diagenesis, compaction, and cementation. These processes can alter the pore structure and connectivity, thus impacting the flow of fluids. Kozhevnikov et al., (2021) discuss how effective pressure influences the permeability of rocks, noting that a decrease in reservoir pressure can lead to a significant reduction in permeability.

The permeability needs to be measured in the reservoir to understand the amount of fluid that will flow through it. Measuring the permeability of reservoir rocks is typically done using core samples and well tests. Core analysis provides direct measurements, while well tests infer permeability through the interpretation of pressure data. Advances in technology have also led to the development of new methods for measuring permeability in tight rocks, which are crucial for unconventional resource plays (CUI et al., 2009).

In reservoir simulation models, permeability is a vital input parameter. It helps in predicting the flow of fluids in the subsurface and is essential for estimating recoverable reserves. Accurate permeability models are necessary to optimize production strategies and enhance oil recovery.

2.4 Fluid saturation of the reservoir rock.

Fluid saturation is a crucial parameter in reservoir engineering and petrophysics. Understanding fluid saturation allows geoscientists and petroleum engineers to characterize reservoir properties effectively and evaluate hydrocarbon recovery potential. Advances in petrophysical measurement techniques, such as well logging and core analysis, have significantly improved our ability to quantify fluid saturation, thereby enhancing reservoir characterization and field development strategies (Schlumberger, 2020).

Oil saturation is the ratio of pore space occupied by oil over the total pore space; the rest of the pore space is occupied by either gas or water or both. Similarly, gas saturation is the fraction of pore space occupied by the gas phase. Fluid saturation is also reported in percent in the literature. It is obvious that the saturation of all fluid phases present in fluid-filled pores would add up to 100% (Satter & Iqbal, 2016).

In conventional oil reservoirs, typical values of oil saturation range between 65% and 85%. Certain oil reservoirs have a gas cap with measurable gas saturation. Dry gas reservoirs generally have high saturation of natural gases, namely, methane, ethane, and heavier components (Lee et al., 2020). Examples of oil, gas, and water saturations are noted in Table. 2 below.

Table 2. Examples of oil, gas, and water saturations in petroleum reservoirs

Reservoir type	Oil saturation (So, %)	Gas saturation (Sg, %)	Gas condensate saturation (Sgc,%)	Connate water saturation (Sw,%)
Oil without a gas cap	65-85	0	0	15-35
Oil with a gas cap	60-70	5-15	0	20-30
Dry gas	0	70-85	0	15-30
Gas condensate	0	40-60	20-40	20

Fluid saturation in a core sample is measured directly by heating and evaporating the fluids from the core and then condensing the vapors in a graduated tube. The procedure is referred to as the Dean–Stark method. Heat is imparted by vaporizing toluene figure 4. Oil and water, being immiscible, are separated in the tube and the volume of water is measured to determine water saturation in the core. Once the water volume and change in the mass of the core before and after the procedure are known, the oil volume that was originally present in the core can be determined (Lee et al., 2020). Fluid saturation in a geologic formation is routinely determined by resistivity log as a well as drilled.

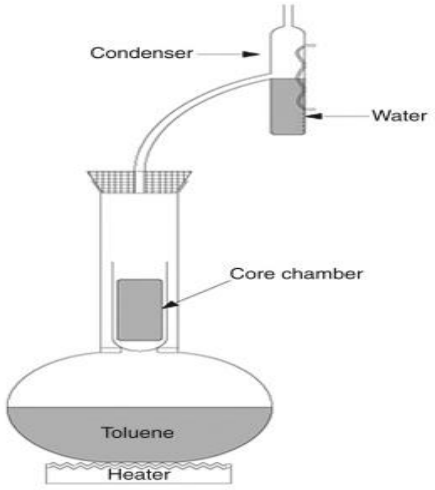


Figure 4. Measurement of fluid saturation by the Dean–Stark method.

The porosity of a reservoir rock is very important because it is a measure of the ability of that rock to store fluids (oil, gas, and water). Equally important is the relative extent to which the pores of the rock are filled with specific fluids. This property is called fluid saturation and is expressed as the fraction, or percent, of the total pore volume occupied by the oil, gas, or water. Thus, for instance, the oil saturation S_o is equal to:

$$S_o = \frac{Volume\ of\ oil\ in\ the\ rock, V_o}{Total\ pore\ volume, V_p} \quad (1)$$

Similar expressions can be written for gas and water. It is evident that:

$$S_o + S_g + S_w = 1 \tag{2}$$

And

$$V_o + V_g + V_w = V_p \tag{3}$$

Ideally, because of the difference in fluid densities, a petroleum reservoir is formed in such a way that, from top to bottom of the sand bed there will be gas, oil, and water, as shown in Figure 5.

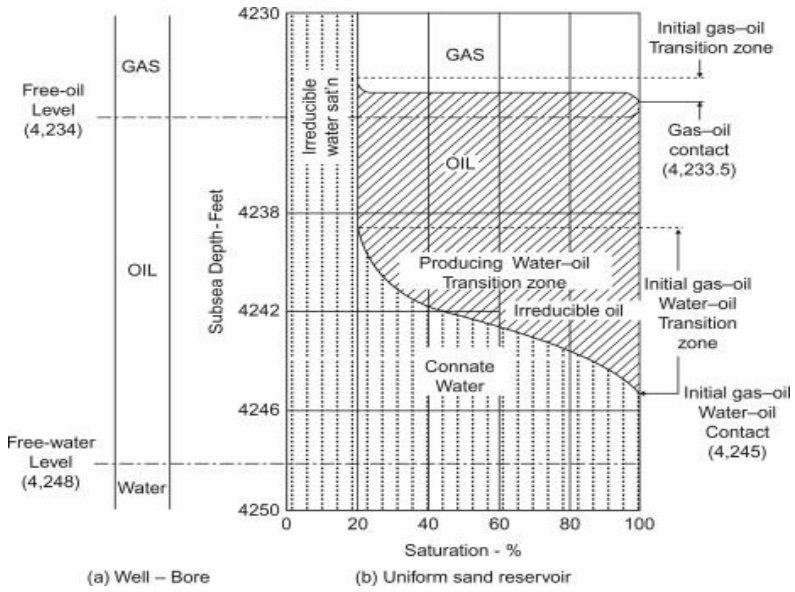


Figure 5. Distribution of fluids in reservoirs.

Connate water, or formation water, is seawater trapped within the pore spaces of sediments during their deposition and lithification, predating oil migration. Its distribution in a reservoir, along with oil and gas, is influenced by density, wettability, and interfacial tension.

CHAPTER 3. METHODOLOGY

3.0 Introduction

This chapter covers the following areas; study area, research design, research methods, and data analysis that will be used to achieve the main objective of the research.

3.1 Area of study

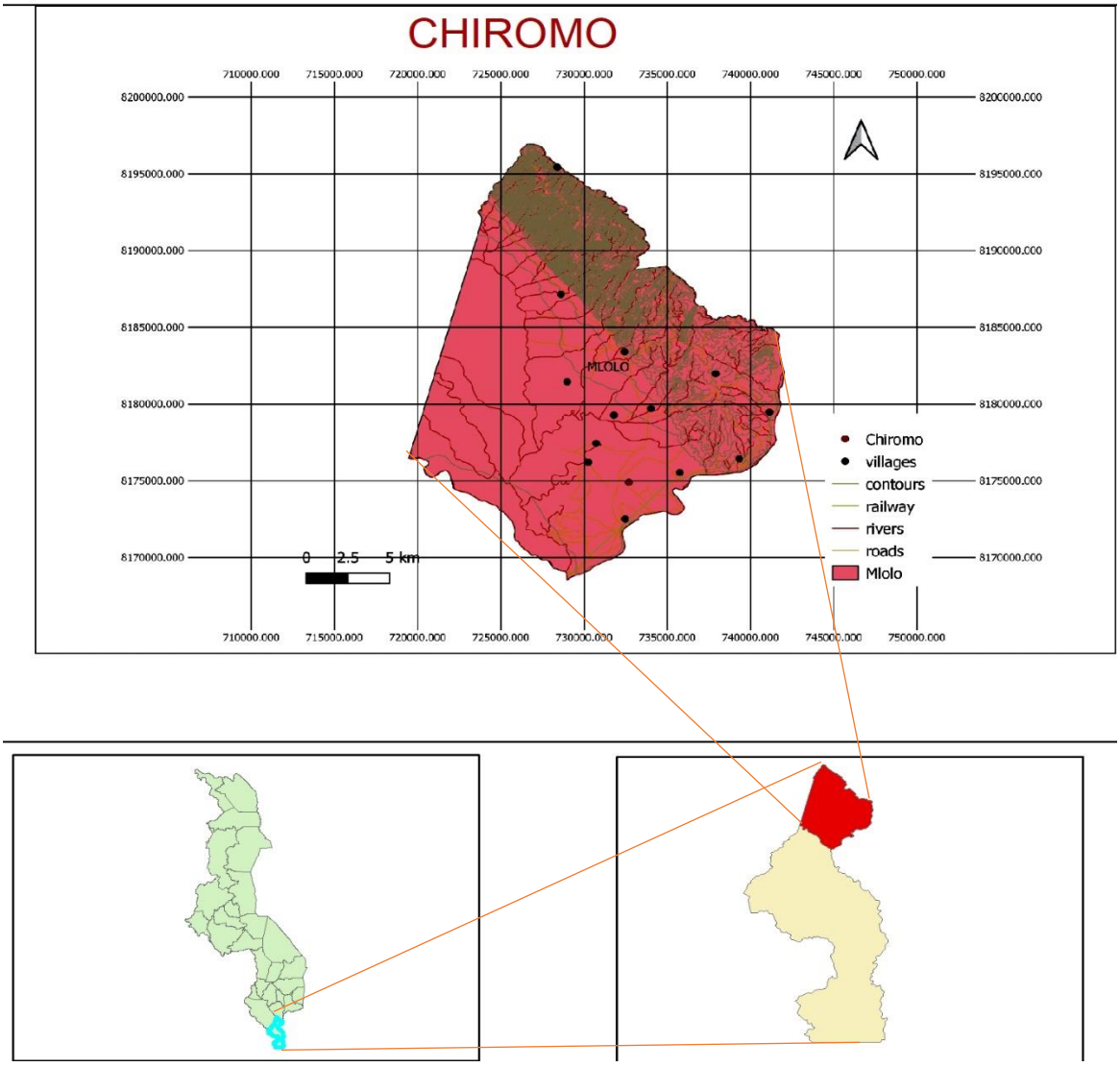


Figure 6. Study area

3.1.1 Geology of the study area

The Chiromo which is in Lower Shire Basin exhibits a stratigraphic complexity influenced by its consolidated sedimentary rocks from the Karroo and Cretaceous periods. The lower shire basin occupies the southern end of Malawi rift. The basin developed during the karoo time and re-activated during the Cenozoic time due to the rifting associated with the EARS (Casting, 1990). A region in southern Malawi, located between latitudes 15°30'S and 16°45'S and longitudes 34°15'E and 35°15'E, near the Malawi-Mozambique border, has been identified as a potential area for hydrocarbon resources.

This area's potential is attributed to previous research in the lower Shire basin, which indicated high levels of organic matter in the deep water due to a slow flow rate allowing for accumulation, a condition favorable for hydrocarbon formation. Furthermore, the presence of coal deposits, derived from organic remains under pressure within sedimentary sequences, strengthens the likelihood of petroleum source rocks. Geologically, the area lies within the Malawi Rift, a part of the Mozambique belt, and is underlain by metamorphic rocks, specifically para- and orthogneiss crystalline rocks (Carter & Bennet, 1973).

Notably, the Chiromo domains are well-known Karoo sedimentary regions within this study area. Detailed geological accounts of this area are documented in various publications of the Geological Survey of Malawi, including work by Habgood (1965).

The sandstones and grits in the basin have demonstrated remarkable porosity and permeability, essential parameters for effective hydrocarbon reservoirs. Specifically, porosity values highlight the excellent storage capacity of these rocks for hydrocarbons, indicating that they can retain significant volumes of oil and gas (Ahmed & Farman, 2023). Meanwhile, the permeability values observed, suggest that these formations facilitate the movement of hydrocarbons, which is crucial for both migration and production.

3.2 Research design

The research is designed as a case study, that used quantitative and qualitative data to determine the lithology, petrophysical properties of reservoir rock of the lower Shire Basin. The secondary data type of data was used to answer the research questions that helped to attain the main objectives of the research. The petrophysical parameters were subjected to a range of parameter approaches. The subdivisions that follow provide a quick overview of approach of the study.

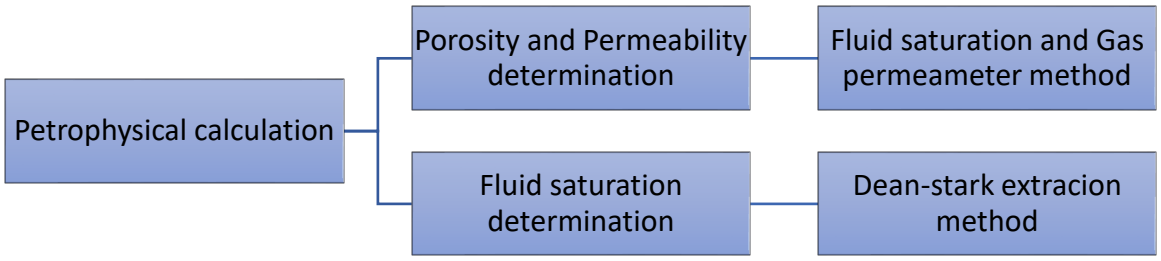


Figure 7. Petrophysical analysis flow.

3.3 Research methods

The research methods cover the following; porosity and permeability determination and determination of the fluids saturated in the reservoir.

3.3.2. Determination of Porosity and permeability

3.2.2.1. Core sample data

The study used secondary data that was obtained from Malawi Geological Survey Department. The samples (ten core samples that were collected from one well at different depth) were collected as cores by coring technique during coalfield test program by BRGM Report of Republic of Malawi, and measurements were taken for horizontal plugs and

properties measured include; porosity and permeability. the methods that were used to analyze the data are; liquid saturation for porosity determination and gas permeameter for permeability determination.

3.2.2.2. Porosity determination

Bakhtiar, (2017), explains the process of liquid saturation method that used in the determination of effective porosity. Weight of a dry, clean sample which has been desiccated is obtained and saturated with brine water for four hours. The sample is removed from the saturating vessel and weighed submerged in the saturating liquid; finally excess liquid is carefully removed and the saturated sample is weighed in air. To find the percentage of porosity this research used the following equation and the calculations are in the appendix A.

$$Porosity = \frac{BV - GV}{BV} \qquad (4)$$

Where PV = Pore Volume,

BV = Bulk Volume and

GV = Grain Volume.

The results of the experiment are shown in Table 2 and calculations are in the appendix A.

3.2.2.3. Permeability Determination

The apparatus for the permeability determination is a gas permeameter, core holder, nitrogen gas and stopwatch. The sample is placed in a core holder and connected to the permeameter and nitrogen is passed through it by laminar flow. They measure flow rate with a bubble tube and record the upstream pressure from the gauge of the regulator (Vincent, 1997). In this research the permeability was calculated using the Equation below.

$$k = \frac{\mu Q L}{A \Delta P} \qquad (5)$$

Where, K = permeability,

μ= viscosity of nitrogen gas,

Q= flow rate,

L= length of core sample,

A= cross sectional area of the sample and

ΔP = upstream pressure-downstream pressure.

Table B-1 in the Appendix B shows the spreadsheet of permeability calculation.

3.3 Determination of fluid present in the reservoir rock

The determination of fluid in the core plugs is carried out using the Dean-Stark extraction method (Bakhtiar, 2017). The necessary equipment including a Dean-Stark apparatus, toluene, a weighing balance, an oven, and thimbles. The distillation extraction (Dean-Stark) technique for assessing fluid saturation relies on the distillation of the water fraction and the solvent extraction of the oil fraction from the sample. Initially, the sample is weighed, and the water fraction is vaporized by boiling a solvent. The vaporized water is then condensed and collected in a calibrated receiver. Additionally, the vaporized solvent condenses, which saturates the sample and extracts the oil. Afterward, the sample is dried in an oven, reweighed, and the oil content is calculated using the gravimetric difference method. Therefore, this research was used the following equations for fluid saturations:

$$Weight\%\ Water(Gravimetric) = \frac{Weight\ of\ Water * 100}{(Initial\ Sample\ Weight)} \quad (6)$$

Or

$$Weight\%\ Water(Volumetric) = \frac{(Volume\ of\ Water) * (Density\ of\ Water) * 100}{(Initial\ Sample\ Weight)} \quad (7)$$

$$Weight\ of\ Solids(Gravimetric) = \frac{Dry\ Weight\ of\ Sample * 100}{(Initial\ Sample\ Weght)} \quad (8)$$

$$Weightof\ Oil(Gravimetric) = \frac{(Initial\ Weight - DryWeight - Weight\ of\ Water) * 100}{(Intial\ Sample\ Weight)} \quad (9)$$

The fluids were normally expressed as percentages of the sample pore space and this required the sample porosity, water density and oil density for the calculations. Therefore, the water and oil saturations were obtained with the formula:

$$\%Water = \frac{Volume\ of\ Water * 100}{(Pore\ Volume)} \quad (10)$$

And

$$\%Oil = \frac{\frac{Weght\ of\ oil}{Density\ of\ oil} * 100}{(Pore\ Volume)} \quad (11)$$

CHAPTER 4. RESULTS AND DISCUSSION

4.0 introduction

This section presents and discusses the findings and results of this research and answering the research questions that aligned with main objective.

4.1 Porosity and permeability determination

The routine core analysis measurements were provided in excel spreadsheet format and the measurements were available for horizontal plugs which includes; grain density, porosity, air permeability, and fluid saturations. Appendix B contains the results in excel spreadsheet Table B-1. and the conventional results of the core experiment are shown in Table B-2. Table 3. is the summary of the result of the study showing the values of porosity and permeability. The average value of the porosity is 14.86±5.10%; average permeability is 349.77±242.98mD.

Table 3. Results of porosity and permeability

S/no	Depth(ft)	Perm.K (mD)	Porosity (%)
596	620	175.424	3.7
612	629	244.222	7.0
595	630	392.850	17.7
597	631	904.124	16.7
602	635	662.601	16.7
603	640	182.942	17.0
610	650	228.439	16.6
611	686	228.347	17.6
626	697	263.157	18.5
635	740	215.642	17.1

4.2.1 Interpretation of Porosity

Porosity was determined from the grain volume and the bulk volume of the sample. Depending on the technique used, different types of porosity were estimated. Porosity measurement by the liquid saturation method indicates only pores that are interconnected (effective porosity) thereby providing a very good estimate of effective porosity for the purpose of reservoir evaluation. The porosities of petroleum reservoirs range from about 5% to 45% and factors determining the magnitude of porosity in sediments are grain sorting, degree of cementation or consolidation, amount of compaction and methods of grain packing (Kun, 2020). If all the grains are of the same size, sorting is said to be good and porosity may be high. If grains are of many sizes and are mixed together, sorting is regarded as poor and porosity in that condition will be reduced. Cementation that takes place during diagenesis also tends to fill in the pore space, so highly cemented sedimentary rocks have lower porosity than poorly cemented sedimentary rocks. Although, round grains and a high content of grain cement gives a high porosity, and angular grains and low cement content yields lower porosity. This research found that porosity values of core plugs ranges from 3.7% to 17.1% at the cored interval. The low porosity values were observed in that interval above and high porosity down that interval. The low porosity intervals were 620 and 629 ft and the high porosity interval were 630 and 740 ft. The average porosity was 14.86, with a standard deviation and variance of 5.10 and 26.06 respectively.

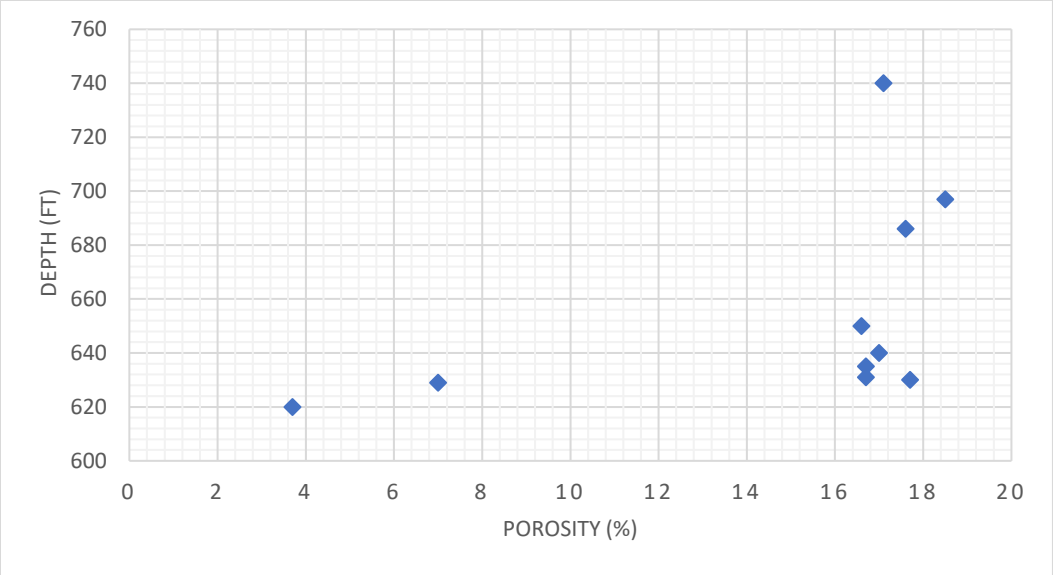


Figure 8 Core porosity versus depth

4.2.1 Interpretation of permeability

The permeability of a rock is controlled by rock grain size, grain shape, degree of cementation or consolidation, grain packing, and clay. The value may vary from less than 1 mD to over 2000 mD (Satter & Iqbal, 2016). In the Chiromo area the value could be above 2000 mD in very permeable formations. The quality of a reservoir as determined by permeability in mD may be scaled as shown in the Table 4.

Table 4. Permeability classification scale

Permeability values (mD)	Classification
Less than 1	Poor
Between 1 and 10	Fair
Between 10 and 50	Moderate
Between 50 and 250	Good
Above 250	Very good

The permeabilities of core plugs are measured horizontally. The horizontally measured permeability is accepted as the rock permeability because it is measured parallel to the bedding which is the major contributor to fluid flow into a typical reservoir (Ebeltoft et al., 2025). Plot of permeability against depth in linear scale is given in Figure 11. Good permeability values seen in the depth interval 740 ft to 640ft and very good permeability values (390 mD, 900 mD and 670 mD) were indicated in depth interval of 630 ft to 635 ft. The depth of 620 ft to 629 ft also has good permeability values as the first depth interval, see Table 4. above for permeability classifications.

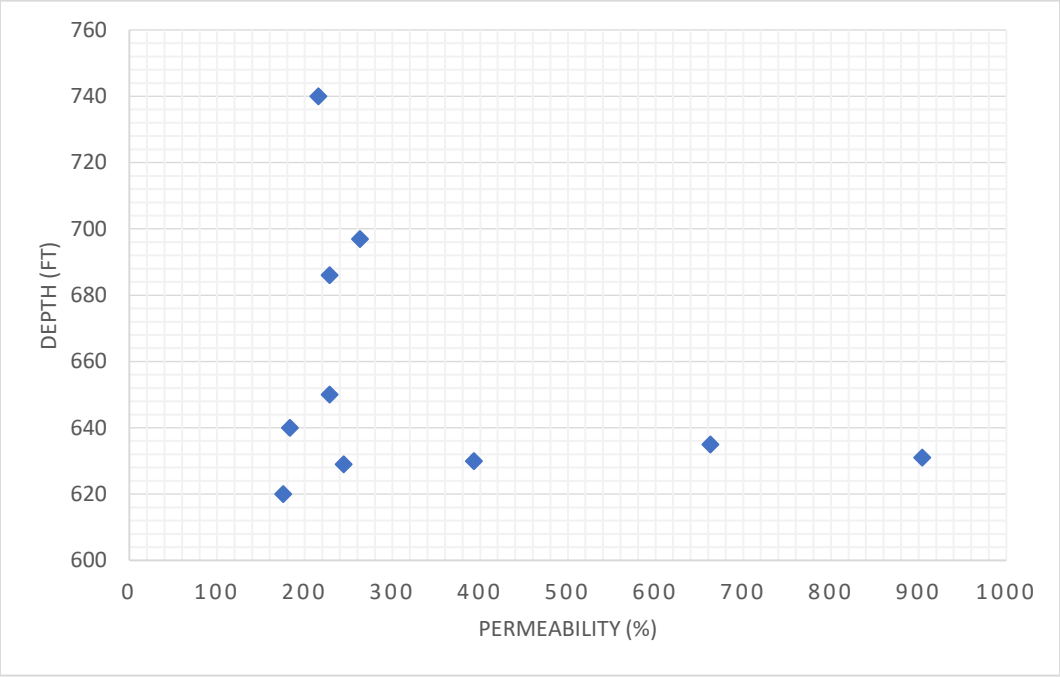


Figure 9. Permeability versus depth

4.3. Interpretation of the fluid that are saturated in the reservoir rock.

Pinto et al., (2018), the principle of saturation dictates that the sum of all fluid saturations (water, gas, oil) in a rock equals 100%. Water saturation (Sw) in a formation, though variable, always includes irreducible capillary water, preventing it from reaching zero. Similarly, residual or irreducible hydrocarbon saturation will always exist in oil or gas reservoirs after displacement (Pinto et al., 2018). Analysis of the sampled well indicated average saturations of 81.93% water (Sw), 13.69% gas (Sg), and 4.38% oil (So). The depth-related variations of these saturations are presented in Figure 6 for the core samples.

Table 5. Fluid saturation of core plugs.

Sample number	Wt. before clean stark(g)	Weight after clean stark(g)	Water produced(cc)	Oil weight(g)	Oil (%)	Water (%)	Gas (%)
596	149.78	147.79	1.90	0.092	4.7	82.2	13.1
612	129.43	126.02	3.38	0.033	1.0	87.7	11.3
595	161.84	149.06	12.08	0.967	6.2	91.3	2.5
597	138.27	129.24	8.70	0.331	3.7	82.8	13.5
602	148.12	138.27	9.77	0.077	0.8	86.6	12.6
603	122.95	115.08	7.36	0.512	6.1	74.5	19.4
610	131.74	123.16	7.96	0.625	7.1	76.9	16.0
611	114.57	106.53	7.21	0.831	10.5	77.4	12.1
626	128.44	119.67	8.66	0.115	1.3	83.5	15.2
635	147.81	138.61	8.96	0.239	2.4	76.4	21.2

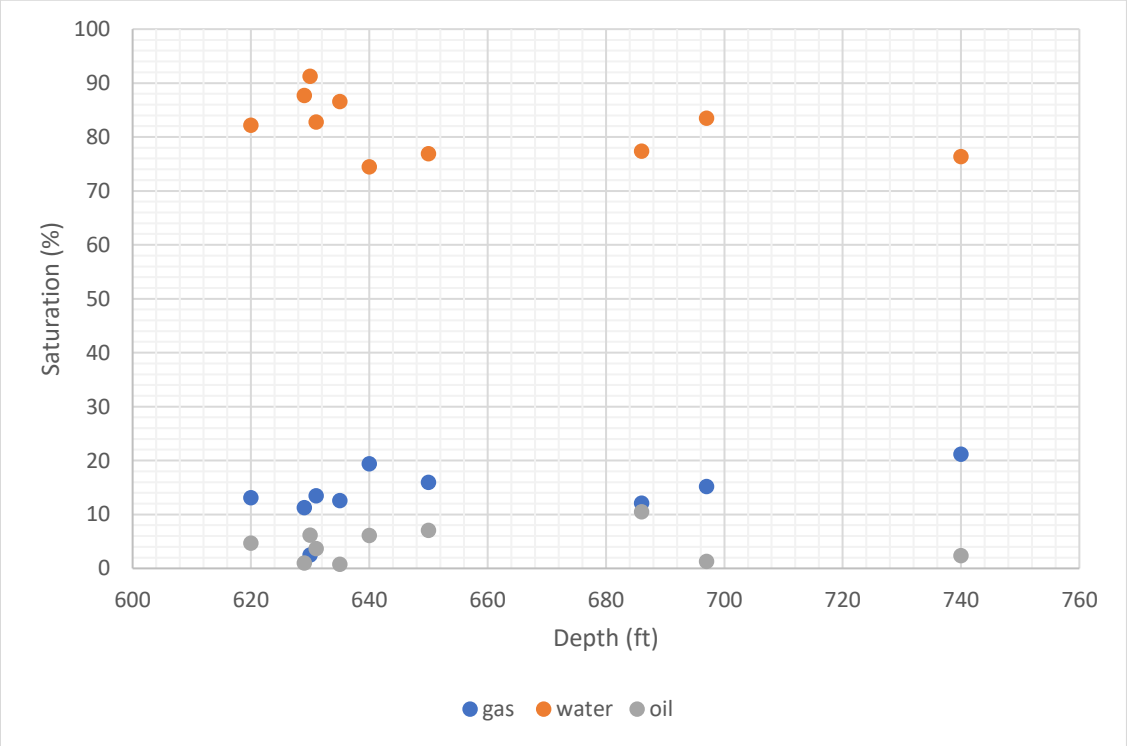


Figure 10. Fluid saturations versus depth.

CHAPTER. 5. CONCLUSION AND RECOMMENDATIONS

5.1 Conclusion

Determination of petrophysical properties of reservoir rock is critical in petroleum exploration. This is the method can be used to calculate the petrophysical properties to assess the presence of reservoir in the area. Calculations can be done using fluid saturation for porosity determination, gas permeameter for permeability determination and dean-star extraction for fluid saturations.

In essence, the exploration into this rock formation reveals a story of varying capacity to hold fluids. The results show that the porosity, are not uniform throughout. In the upper section examined, that spaces were quite limited, suggesting a tighter grip on any potential oil or gas. However, as we delved deeper, the rock opened up, showing significantly larger and more abundant pore spaces. This deeper zone appears to be a much better natural storage for valuable resources.

Looking at how easily fluids can move through these rocks, the permeability, we saw a similar trend. The zones with higher storage capacity also generally allowed for easier flow, particularly in a specific deeper interval that showed remarkably good connectivity. Interestingly, even in the tighter upper sections, there were still pathways for fluids to move. Finally, when we looked at the proportions of different fluids within the rock, we found a dominance of water, with smaller amounts of gas and even less oil. This snapshot of fluid distribution helps us understand the current state of the reservoir and hints at the challenges and opportunities for potential resource extraction.

5.2 Recommendations

A petroleum system can be assessed using methods such as geological, geological and GIS techniques as well as petrophysical calculations as exempted in this research. Therefore, according to the results and existing literature, the following have been suggested for potential research directions. Further research must be carried out to pin point the specific petroleum systems within the six hydrocarbon blocks. This is because the petrophysical

properties of the reservoir rock individual cannot represent whole petroleum systems in the area.

It is important as it will allow that the assessment of the petroleum systems to be conducted specific scope which will provides high level of detail which is necessary to the research as compared to a broader scope which provides a rather narrow level of detail. The previous assessment was based on the presence of the reservoir rock and the source rock. Therefore, the collection of other petrophysical data such as shale and clay volume as well as data on curvature and roughness of the reservoir tops which will assist assessing the petroleum system in terms of the reservoir, trap and seal respectively.

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APPENDICES

Appendix A

1. Porosity

$$Porosity = \frac{BV - GV}{BV}$$

$$Porosity = \frac{62.93 - 60.62 * 100}{62.93} = 3.7\%$$

$$Porosity = \frac{54.86 - 51.01 * 100}{54.86} = 7.0\%$$

$$Porosity = \frac{74.9 - 61.67 * 100}{74.9} = 18.6\%$$

2. Permeability

$$k = \frac{\mu Q L}{A \Delta P}$$

$$k = 1000 * \frac{0.017747 * 1.186585 * 6.944}{11.0609966 * 0.032798} = 392.852$$

$$k = 1000x \frac{0.017756x0.194069x6.995}{11.283x0.012384} = 175.424$$

$$k = 1000x \frac{0.017747x1.235399x5.797}{11.283x0.012384} = 904.124$$

3. Fluid saturations

$$\%Water = \frac{Volume\ of\ Water * 100}{(Pore\ Volume)}$$

$$\%Water = \frac{1.90}{2.31} x100 = 82.2\%$$

$$\%Water = \frac{3.38}{3.85} x100 = 87.7\%$$

$$\%Water = \frac{12.08}{13.23} x100 = 91.3\%$$

$$\%Oil = \frac{\frac{Weght\ of\ oil}{Density\ of\ oil} * 100}{(Pore\ Volume)}$$

$$\%Oil = \frac{(0.092)/(0.847)}{(2.31)} x100 = 4.7\%$$

$$\%Oil = \frac{(0.033)/(0.847)}{(3.85)} x100 = 1.0\%$$

$$\%Oil = \frac{(0.967)/(0.847)}{(13.23)} x100 = 6.2\%$$

%Gas=100-(%Water+%Oil),

since in the formation fluid saturation add up to 100%

$$\%Gas = 100 - (4.7 + 82.2) = 13.1\%$$

$$\%Gas = 100 - (1.0 + 87.7) = 11.3\%$$

$$\%Gas = 100 - (6.2 + 91.3) = 2.$$

Appendix B

Table B-1. Excel worksheet showing the template used in calculating permeability of the plugs Insert Table B-1.

Sample number	Test Pressure (psi)	Baro. Pressure (inches)	Temp. (˚C)	Gas Viscosity (cP)	Volume Timed (cc)	Ave Time (secs)	Length (cm)	Diameter (cm)	Pressure (p) (atm)	Flow rate (Q) (cc/sec)	Area (A) (Cm^2)	Barometric (B) (atm)	Permeability (K) (mD)
595	0.5	30.61	25	0.017747	25	20.5	6.944	3.736	0.032798	1.186585	11.17016	1.023027	392.9
596	0.2	30.6	25.2	0.017756	25	128.82	6.995	3.747	0.012384	0.194069	11.02843	1.022693	175.4
597	0.2	30.65	25	0.017747	25	19.69	5.797	3.79	0.012384	1.235399	11.283	1.024364	904.1
602	0.2	30.67	26	0.017792	25	28.56	6.082	3.77	0.012384	0.851716	11.16423	1.025033	662.6
603	0.2	30.65	25	0.017747	25	88.22	5.225	3.779	0.012384	0.275731	11.2176	1.024364	182.9
610	0.2	30.6	25	0.017747	25	72.47	5.468	3.817	0.012384	0.335656	11.44433	1.022693	228.4
611	0.2	30.62	25	0.017747	25	69.72	5.016	3.728	0.012384	0.348896	10.91687	1.023362	228.3
612	0.2	30.65	25	0.017747	25	75.2	5.883	3.759	0.012384	0.323471	11.09918	1.024364	244.2
626	0.2	30.65	25	0.017747	25	68.47	5.677	3.728	0.012384	0.355265	10.91687	1.024364	263.2
635	0.2	30.6	25	0.017747	25	90.3	6.351	3.793	0.012384	0.26938	11.30087	1.022693	215.6

Table B-2. Results of conventional core measurement of the core plugs

S/no	Bulk vol(cc)	Dry wt(g)	Wet wt(g)	Immersed wt(g)	Grain vol(g)	Grain density (g/cc)	Pore vol (cc)
596	62.93	147.79	150.1	87.17	60.62	2.44	2.31
612	54.86	126.02	129.87	75.01	51.01	2.47	3.85
595	74.9	149.06	162.29	87.39	61.67	2.42	13.23
597	63.01	129.24	139.75	76.74	52.50	2.46	10.51
602	67.52	138.27	149.55	82.03	56.24	2.46	11.28
603	58.04	115.08	124.96	66.92	48.16	2.39	9.88
610	62.26	123.16	133.51	71.25	51.91	2.37	10.35
611	52.93	106.53	115.84	62.91	43.62	2.44	9.31
626	56.03	119.67	130.04	74.01	45.66	2.62	10.37
635	68.73	138.61	150.34	81.61	57.00	2.43	11.73