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Calculating Porosity and Permeability Values to Assess Pore Distribution with the Mercury Injection Capillary Pressure Technique

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Abstract

This research focuses on determining the values of porosity and permeability in rocks by examining pore distribution through the Mercury Injection Capillary Pressure method. This technique operates on the concept of capillary pressure, where mercury is forced into a rock specimen under increasing pressure to analyze the size and arrangement of its pores. The data gathered from these measurements enables the calculation of effective porosity and absolute permeability by utilizing the Washburn and Katz-Thompson formulas. Findings indicate that variations in porosity and permeability are affected by factors such as rock texture, grain dimensions, and the connectivity between pores. Rocks with evenly distributed pores exhibit greater permeability compared to those with poorly connected pore structures. Overall, the MICP technique has demonstrated its effectiveness in delivering a quantitative understanding of pore microstructures and can be effectively utilized for reservoir characterization within the field of petroleum geology.

1. Introduction

Porous rocks are crucial elements in the upstream oil and gas industry as they serve as storage vessels and fluid transport pathways, with porosity and permeability being key parameters determining reservoir quality. Accurate characterization of these pore systems can be achieved using the Mercury Injection Capillary Pressure (MICP) method, which applies the principles of capillary pressure and Washburn's Law to measure the pore neck size distribution through the injection of mercury as a non-wetting fluid. This theoretical basis is reinforced by the Katz and Thompson (1987) model, which uses percolation theory to more elegantly link the relationship between microscopic pore geometry and macroscopic rock permeability values. Previous studies by Adhi Nugroho et al. (2024) and Rahman (2023) have explored the effect of capillary pressure on rock physical properties through laboratory tests, but challenges in accurately predicting permeability due to variations in pore texture and connectivity still require more in-depth analysis [1] The novelty of this study lies in the utilization of pore distribution data from MICP testing integrated with the Katz and Thompson correlation model to quantitatively estimate porosity and permeability values in specific rock samples. This study aims to provide a more accurate reservoir characterization reference by utilizing important parameters such as pressure threshold and characteristic length to understand the fluid flow mechanism under actual reservoir conditions.

Reservoir characterization is crucial because it helps to create successful field development strategies and precisely estimate hydrocarbon reserves. Having a thorough understanding of rock physical qualities, or petrophysical characteristics, throughout a reservoir's whole life cycle is essential to foreseeing how effectively the rock might retain and transport fluids. Two crucial aspects that are regularly evaluated are porosity and permeability [7]. Porosity shows the reservoir's static capacity to hold fluids, while permeability measures how well the rock can let fluids flow through it under a pressure gradient. However, just reviewing total porosity using regular core analysis (RCAL) might not be sufficient to explain the actual flow behavior in complex and diverse formations. This restriction results from the fact that fluid flow is impacted by the internal architecture of the pore network, particularly the size and connectivity of pore throats, rather than just by the overall accessible pore space [8].

The problems in describing these very fine-grained pore architectures grow increasingly clear as the focus turns to obtaining resources from unconventional and marginal reservoirs. Reservoir rocks usually have a wide spectrum of pore sizes from macro to nanoscale; carbonates or extremely cemented sandstones are especially notable in this regard [9]. This variation in pore form results in significant microscopic differences in which the channels for fluid flow may be significantly obstructed by the extreme narrowing of pore necks. Therefore, advanced techniques able to quantitatively examine the spectrum of pore diameters are required. The mercury injection capillary pressure (MICP) method is one of the most well-known and successful ways to reach this [10].

The fundamental ideas of capillary tension and surface energy underpin the MICP method. Under progressively rising pressure, this process involves injecting mercury, a fluid with a very high surface tension that does not wet the rock, into the pore gaps of the rock. Using mercury for pore analysis has a historical basis in Washburn's classical capillarity theory from 1921. The Washburn equation shows how much pressure is needed to push liquid into a capillary tube and the tube's radius are basically connected. Regarding reservoir rocks, every increase in injection pressure indicates the energy required for mercury to enter progressively smaller pore necks. Researchers can produce an exact curve showing the distribution of pore neck diameters by tracking the quantity of mercury added at every pressure step [11].

2. Research Methodology

The research took place at the Center for Survey and Testing of Electricity, New, Renewable Energy, and Energy Conservation located in Jakarta, known as BBSP KEBTKE/LEMIGAS.

2. 1. Research Flow

The process begins with Special Core Analysis (SCAL) using a Micromeritics AutoPore instrument. Primary data collected includes capillary pressure, cumulative volume, and incremental mercury volume. The data analysis steps include:

a. Plot the Pc vs. Sw curve.
b. Analyze the Pore Size Distribution.
c. Calculate Porosity based on bulk density and cumulative volume.
d. Estimate Permeability using the Katz-Thompson correlation.

2. 2. Experimental Device

The experiment used a solid-state penetrometer to accommodate a 16-gram rock sample. The analysis was conducted in two phases: low pressure (up to 50 psia) and high pressure (up to 60,000 psia).

3. Results and Discussion

This section presents the results of experiments conducted using a Micromeritics AutoPore instrument with a mercury injection pressure range of 0.512104 psi to 59,979.87 psi. The average pressure during the intrusion process was recorded at 15,955.54 psi, indicating a predominance of small to medium-sized pores in the tested rock samples.

Pore distribution assessments in rock reservoir samples were performed using the Mercury Injection Capillary Pressure (MICP) technique. Mercury, which does not wet surfaces, is injected into prepped and dried rock samples at gradually increasing pressures. According to the collected data, the initial pressure for injection starts at a very low level and is progressively increased until reaching the highest pressure (for instance, from 19.99 psi to 22.99 psi, then to 36.90 psi, and finally surpassing 87. 85 psi). Each rise in capillary pressure (Pc) signifies the intrusion of mercury into pore throats with reduced radii.

During the early phases of the injection, mercury infiltrates the macropores that have the largest pore throat radii. The moment when mercury first establishes a continuous intrusion network throughout the sample is referred to as the displacement pressure (Pd). A low Pd value signifies that the rock has predominantly well-connected macroporosity, while a high Pd value suggests the presence of very fine grains or significant cementation in the rock. The shape of the curve representing capillary pressure against mercury saturation (SHg) directly reflects the quality of the sorting of pore throats. A plateau in the curve indicates outstanding pore throat sorting, indicating that most of the pore volume is filled within a narrow pressure range. On the other hand, a curve that slopes gradually indicates a high degree of heterogeneity within the rock's pore network.

3.1 Capillary Pressure Analysis

The relationship between capillary pressure (Pc) and wet phase saturation (Sw) is depicted through a Pc vs. Sw graph. Based on the data, when the wet phase saturation approaches 0%, the capillary pressure value jumps to nearly 100,000 psia. This indicates the strong resistance of the micropores to the entry of non-wetting fluids. Conversely, when the water saturation approaches 100%, the capillary pressure drops sharply to around 0.1 psia, which means that almost all the pore space has been naturally filled with the wet phase.

3.2 Pore Size Distribution (PSD)

Pore size distribution analysis was carried out through incremental pore volume and cumulative pore volume curves :

a. Incremental PV: Shows fluctuations in the medium to large pore size range, which is around 0.1 - 10 μm.
b. Cumulative PV: Declines sharply across the same size range, confirming that the majority of the pore volume in the sample is contributed by pores in the mesopore to macropore category. This broad distribution across the size range supports smoother fluid flow within the rock.

3.3 Porosity and Permeability Calculation

The quantitative calculation results indicate that the sample has significant storage capacity and flow capacity. Summary calculation data are presented in the table 1:

TABLE 1. Summary of Petrophysical Properties

Parameters	Calculation Results	Units
Pore Volume	1.6628	ml
Bulk Density (Y_b)	1.9942	g/ml
Sample Weight	16	gram
Porosity Results	20.78	%
Pressure Threshold	23.7846	Psia
Characteristic Length (L_{char})	7.6042	μm
Permeability Results	15.0454	mD

The porosity value of 20.78% categorizes this rock as a "Good" reservoir [3]. Meanwhile, the permeability value of 15.05 mD is included in the low-moderate category, but remains within the economic range for production and injection activities, depending on the viscosity of the associated reservoir fluid [2]. The use of the Katz-Thompson model has proven effective in linking microscopic parameters such as pore throat with macroscopic flow properties of the rock.

MICP data were further utilized to estimate the absolute permeability of the rock. Permeability is influenced by both the overall volume of void space, known as porosity, and is significantly affected by the radius of the pore throats that act as channels connecting the pores. This research employed the Katz-Thompson correlation along with the Swanson model for the capillary dataset.

An important aspect of the Katz-Thompson model is identifying the critical pore radius (rc), which is determined from the initial inflection point in the pore size distribution curve, marking the onset of noticeable hydraulic conductivity. In contrast, the Swanson parameter is obtained from the peak of the mercury saturation-to-capillary-pressure (S_{Hg}/P_c)max curve, indicating the main interconnected pore spaces that primarily govern fluid movement. When these theoretical models are compared to Routine Core Analysis (RCAL) data, they show a remarkable degree of accuracy. Any slight discrepancies noted are usually a result of rock compressibility effects under high injection pressures or the existence of natural microfractures observed at the initial pressure (Pd) [9].

In summary, this investigation reveals that variations in texture, such as differences in grain size, levels of compaction, and the occurrence of authigenic clay minerals, directly impact the geometry of pore throats, ultimately influencing both the effective porosity and permeability of reservoir rocks.

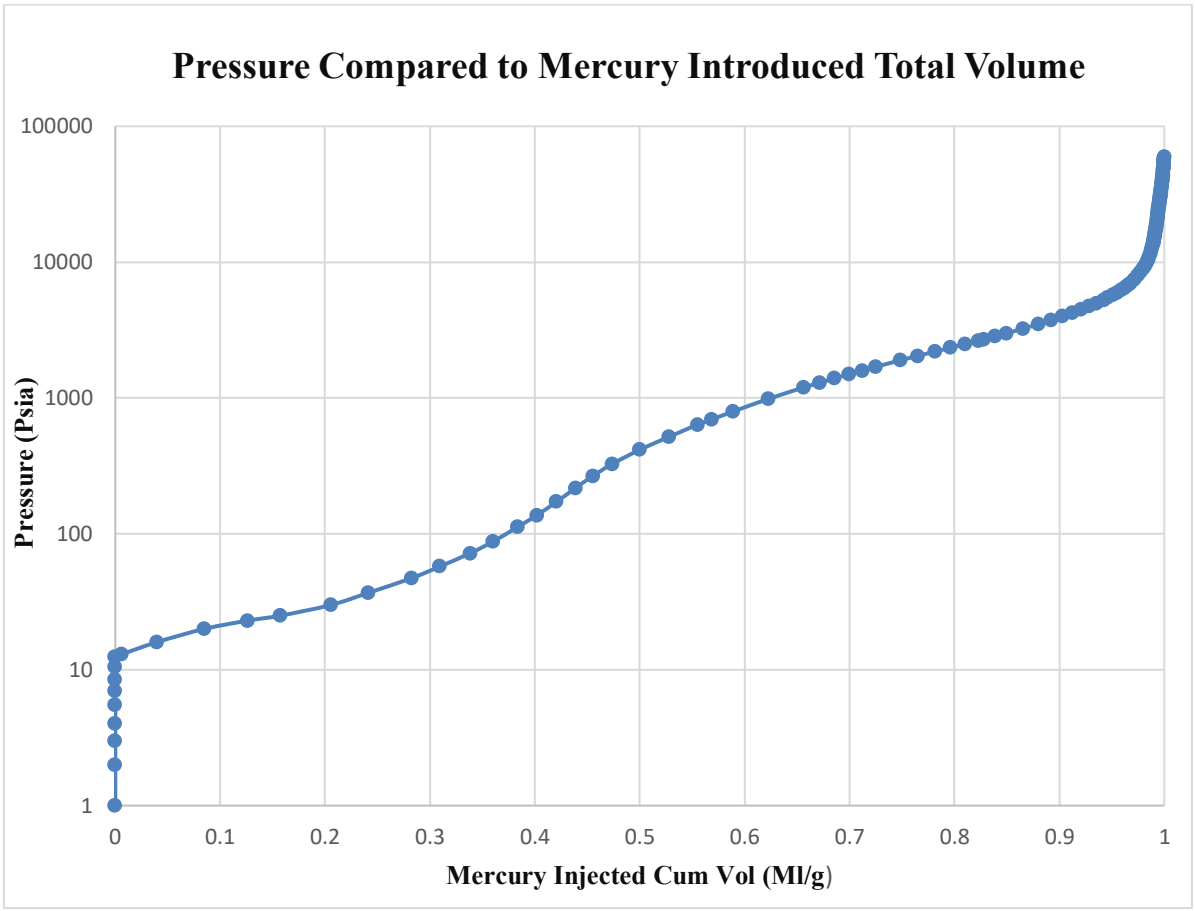


FIGURE 1. Plot of Pc Curve vs. Cumulative Mercury Injected Volume

Figure 1 shows the relationship between injection pressure and the cumulative volume of mercury injected during the Mercury Injection Capillary Pressure (MICP) test [10]. The increase in cumulative mercury volume with increasing pressure indicates a gradual intrusion of mercury into the rock pore system, from large pores at low pressure to very small pores at high pressure. The sharp increase in pressure at the final stage of intrusion indicates the dominance of micropores with very small diameters that require high pressure to penetrate [11].

4. Conclusion

The MICP method proved accurate in identifying the storage capacity and flowability of rocks. The study concluded that the rock samples had a porosity of 20.78% and a permeability of 15.05 mD. These results provide a solid basis for reservoir performance evaluation and multiphase flow simulation.

The MICP technique is recognized as a remarkably accurate analytical method, not just for assessing effective porosity but also for comprehensively detailing the geometry and distribution of pore throat sizes, which routine rock core analysis cannot accomplish alone.

Utilizing the Washburn equation on capillary pressure data effectively illustrates the variations within the pore network. The features of the capillary pressure curve, particularly the pressure-displacement point (Pd) and the slope's plateau, are directly linked to the quality of pore sorting in the rock, where flatter curves indicate reservoirs with better flow characteristics.

The textural properties of the rock, such as cementation level, grain dimension, and the occurrence of microfractures, play a crucial role in determining pore distribution. Rocks that exhibit high porosity but have

poor connectivity of pore throats (as shown by mercury injection under high pressures) will have low permeability, underscoring the need for microstructural analysis in evaluating formations.

This detailed comprehension of pore structure carries important consequences for reservoir engineering, especially when it comes to forecasting irreducible water saturation, formulating fluid injection plans (Enhanced Oil Recovery), and improving management of production rates in diverse formations.

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Data Availability Statement

The data supporting the findings of this study are available upon request from the corresponding author for corporate data privacy reasons.

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