UM SISTEMA DE LABORATÓRIO PARA INVESTIGAÇÃO DA CAPACIDADE DE FLUXO DE FLUIDOS ATRAVÉS DE AMOSTRAS DE AREIA NÃO CONSOLIDADAS

A LABORATORY SYSTEM FOR INVESTIGATING OF FLUIDS FLOW CAPACITY THROUGH UNCONSOLIDATED SAND SAMPLES

تصميم منظومة مختبرية لفحص كفاءة جريان السائل خلال نماذج رملية غير متماسكة

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RESUMO

Praticamente todos os estudos de engenharia de reservatório envolvem conhecimento detalhado das características do fluxo de fluido. O desempenho do fluxo de fluido em meios porosos é afetado pela pressão, taxa de fluxo e volume de fases de fluido único. A permeabilidade é uma medida de quão bem um meio poroso permite o fluxo de fluidos através dele. A permeabilidade e a porosidade formam as duas características significativas das rochas de reservatório. Esta pesquisa teve como objetivo apresentar o projeto de equipamentos de laboratório para testar a capacidade de escoamento de fluidos em diferentes amostras de arenito. Duas amostras de areia (amostra de areia grossa e amostra de areia fina) foram testadas. As medidas laboratoriais de porosidade, saturação, permeabilidade total, permeabilidade efetiva e permeabilidade relativa foram avaliadas. Os testes de laboratório foram realizados em areia de núcleo não consolidada parcialmente saturada para escoamento de fluido bifásico. O trabalho experimental foi desenvolvido para medir a capacidade de fluxo alcançada pelo método de condições de estado estacionário. Vários tamanhos de grãos de areia foram selecionados como um meio poroso para determinar as propriedades petrofísicas e a capacidade de fluxo de fluido da amostra de rocha. Nitrogênio e ar foram utilizados como fases gasosas e, para fases líquidas, a água foi escolhida como fluido de injeção. O método de processo em estado estacionário foi usado para determinar a permeabilidade e a permeabilidade relativa de areias não consolidadas ao fluxo de água. Taxas de fluxo diferentes foram medidas para gradientes de pressão diferentes em um fluxo viscoso. À medida que a taxa de fluxo aumenta, a diferença de pressão também aumenta. Pode-se observar que existe uma correlação e relação direta entre a vazão e a diferença de pressão. A permeabilidade absoluta do plug do núcleo foi medida usando a equação de Darcy. A permeabilidade absoluta não depende das características do fluido, mas apenas das propriedades do meio. O recipiente de amostra que contém uma quantidade mais significativa de areia, diminui a permeabilidade e, portanto, requer alta pressão para o fluido escoar dentro da amostra.

Palavras-chave: *fluxo de fluido; permeabilidade; permeabilidade efetiva; permeabilidade relativa; meio de poros.*

ABSTRACT

Practically all studies of reservoir engineering involve detailed knowledge of fluid flow characteristics. The fluid flow performance in porous media is affected by pressure, flow rate, and volume of single fluid phases. Permeability is a measure of how well a porous media allows the flow of fluids through it. Permeability and porosity form the two significant characteristics of reservoir rocks. This research aimed to present the design of laboratory equipment to test the ability of fluid flow through different sandstone samples. Two sand core samples (coarse sand sample and fine sand sample) were tested. The laboratory findings measurements of porosity, saturation, total permeability, effective permeability, and relative permeability were evaluated. The laboratory tests were performed on partially saturated, unconsolidated core sand for two-phase fluid flow. The experimental work was developed for measuring the flow capacity achieved under the steady-state conditions method. Various grain sizes sands were selected as a porous medium to determine petrophysical properties and fluid flow capacity of the rock sample. Nitrogen and air were utilized as gas-phases, and, for liquid-phases, water was chosen as an injection fluid. The steady-state process method was used to determine the permeability and relative permeability of unconsolidated sands to water flow. Different flow rates were measured for different pressure gradients in a viscous flow. As the flow rate increases, the pressure difference also increased. It can be observed that there are a direct correlation and relationship between the flow rate and the pressure difference. The core plug's absolute

permeability was measured using Darcy Equation. Absolute permeability does not depend on fluid characteristics but only on media properties. The sample container contains a more significant amount of sand, decrease the permeability, and therefore requires high pressure for fluid flowing within the sample.

Keywords: fluid flow; permeability; effective permeability; relative permeability; pores media.

المخلص

عملية جميع دراسات هندسة المكائن تتضمن معرفة تفصيلية لخصائص تدفق السوائل. يتأثر أداء تدفق السوائل في الوسط المسامي بالضغط ومعدل التدفق وحجم الطور السائل الاحادي. النفاذية هي مقياس لمدى سماح الوسائط المسامية بتدفق السوائل من خلالها. تشكل النفاذية والمسامية خاصيتين مهمتين لصخور المكمن. يهدف هذا البحث إلى تصميم منظومة مختبرية لفحص كفاءة تدفق السوائل عبر عينات مختلفة من الحجر الرملي. حيث تم اختبار عينتين من عينات الحجر الرملي في هذه الدراسة، احدهما الحجر الرملي الخشن والاخر الحجر الرملي الناعم. تم استحصا على النتائج المختبرية مثل قياسات المسامية والتشبع والنفاذية الكلية والنفاذية الفعالة والنفاذية النسبية من خلال اجراء التجارب العملية لتدفق السوائل ثنائية الطور على الحجر الرملي الغير المتماسك والمشبّع جزئيًا. عند تصميم وبناء المنظومة المختبرية تم الاخذ بنظر الاعتبار ان قياس وحساب سعة التدفق يكون تحت الظروف الحالة المستقرة. تم اختيار احجام مختلفة من الحجر الرملي كوسط مسامي لقياس الخواص البتروفيزيائية وقابلية جريان السوائل للنماذج الصخرية. من الجدير بالذكر تم استخدام النيتروجين والهواء كطور غازي، وبالنسبة للطور السائل، تم اختيار الماء كسائل حقن. تم الاعتماد على جريان الحالة المستقرة لإيجاد النفاذية والنفاذية النسبية للحجر الرملي الغير المتماسك لجريان الماء في الوسط المسامي. عند الجريان اللزج تم قياس معدلات تدفق مختلفة لتدرجات هبوط ضغوط مختلفة. وتبين ان الزيادة الحاصلة في معدل جريان السائل يقابله زيادة في فرق الضغط أيضًا. مما نلاحظ من الاستنتاجات أعلاه ان هناك علاقة طردية بين معدل التدفق وفرق الضغط. تم قياس النفاذية المطلقة للعينة باستخدام معادلة دارسي. النفاذية المطلقة تعتمد على خصائص الوسط المسامي ولا تعتمد على خصائص سائل الجريان. إن وعاء العينة الذي يحتوي على كمية أكبر من الحجر الرملي تكون فيه النفاذية اقل مايمكن، لذلك يتطلب ضغطًا أعلى لجريان السوائل داخل العينة.

الكلمات المفتاحية: جريان الموائع; النفاذية; النفاذية الفعالة; النفاذية النسبية; الوسط المسامي

1. INTRODUCTION:

Fluid flow through porous media is an issue that has been addressed in many branches of engineering and science, e.g., soil water hydrology, reservoirs engineering, chemical engineering, soil science, and soil mechanics (Jacob Bear, 2013). Porous media fluid flow is a significant phenomenon in a wide variety of applications, including landslides risk assessment, groundwater hydrology, and biophysical systems (Rahimi-Gorji *et al.*, 2016).

A better understanding of the fluid flow fundamental through petroleum-reservoir rock is key to improving petroleum production methods (Vafai, Kambiz, 2015). Fluid flow is a complicated transportation process through porous media. The porous médium of material comprises a solid matrix with interconnected voids (pores). The interconnectedness of the pores permits the flow of one or more fluids through the material (D. B. Ingham *et al.*, 2012). In the simplest case, that is to say, 'single-phase flow,' the pores are saturated by a single fluid, while in 'two-phase flow' the void space shared with two fluids. Examples of porous media are sandstone and limestone rocks (D. B. Ingham *et al.*, 2012). The single-phase flow mathematical equations describe the physical processes which represent the relationship between porous medium rocks and fluids to the conditions of the flow (Yahya J. Tawfeeq, 2020). The movement of single-phase liquids across porous media is controlled by Darcy's law (Monicard, 1980; Amyx, 1960), which applies to

incompressible fluids. A calculation of capacity to move fluids of permeable material is specified by the transport coefficient called permeability (Tiab and Donaldson, 2012; Ekwere, 2012). This coefficient of transport is called the absolute permeability in the single-phase flow equation. However, where more than one fluid is in the porous medium, an effective permeability must be defined for each fluid phase. Two laboratory measurement methods are commonly used to evaluate the fluid flow capacity, steady-state method, and unsteady-state method (S. Abaci *et al.*, 1992).

In steady-state methods, constant flow rate and pressure are used to drive a fixed volume ratio of two phases simultaneously through the porous medium until stable saturation and differential pressure. On the other hand, unsteady-state technique includes displacing the saturated fluid phase by injecting another fluid phase, such as displacing oil by water. Also, the saturation equilibrium is not reached in this method. Steady – State techniques for calculating permeability more commonly used, arising from the consistency of mathematical study based on Darcy's Equation and the assumption that saturation is directly calculated. The steady-state approaches provide accurate permeability results for two or three fluids that are simultaneously injected at constant pressure and rates. For these reasons, the course of the steady-state was used in this study.

Darcy's law is the fundamental law of fluid movement in porous media. The mathematical

definition established in 1856 states that "the velocity of a homogeneous fluid in a porous medium is proportional to the gradient of the pressure and inversely proportional to the viscosity of the fluid" (Tarek and McKinney, 2005). Darcy equation was established in 1856 by Henry Darcy (Frick, 1962; Engler, 2003) for incompressible single-phase fluids flow (water) and expressed as shown in Eq. 1 (Olivier, 2005; Martin, 2011; Tarek, 2010):

$$v = \frac{q}{A} = \frac{k}{\mu} \left(\frac{dp}{dl} \right) \quad (1)$$

Where:

v = fluid flow superficial velocity (cm/sec)

q = flow rate (cm³/s)

k = permeability (Darcy)

A = cross-sectional area of sample (cm²)

ΔP = pressure differences (atm)

μ = fluid viscosity (cp)

L = sample length (cm)

For the permeability 'K', Eq. 1 could be transposed as Eq. 2:

$$K = \mu \frac{q}{A} \frac{L}{\Delta P} \quad (2)$$

The permeability dimensions are defined by substituting " μ , q , L , A , and ΔP " units in the above Equation. The Darcy unit derives from the selecting of "cgs" system units as shown Eq. 3.

$$\text{darcy } [D] = \frac{q \left[\frac{\text{cm}^3}{\text{s}} \right] \mu [\text{cp}] L [\text{cm}]}{\Delta P [\text{atm}] A [\text{cm}^2]} \quad (3)$$

In the early 1900s (Chalmers *et al.*, 1932; Muskat, 1937; Botset, 1940; Tiab and Donaldson, 2012), theoretical aspects and measuring methods relevant to the permeability studied. Muskat *et al.* (1937) showed that "the volumetric flow rate can be written individually for each fluid/phase flowing into the pore" (Olivier, 2005) as follows (Eq. 4):

$$Q_i = \left(\frac{K_n}{\mu_n} \right) \frac{A}{L} \Delta P \quad (4)$$

Where:

Q_n = flow rate of phase n (cm³/s)

K_n = phase " n " effective permeability (Darcy)

μ_n = fluid " n " viscosity (cP)

ΔP = pressure differences (atm)

L = core length (cm)

A = cross sectional area (cm²)

Muskat *et al.* (1937), suppose that the law of Darcy applies to any fluid when the fluids are liquid and gas, and showed that ' q ' could be written as a volumetric flow rate (Eq. 5 and 6):

$$Q_g = \left(\frac{K K_{rg}}{\mu_g} \right) \frac{A}{L} \Delta P_g \quad (5)$$

$$Q_l = \left(\frac{K K_{rl}}{\mu_l} \right) \frac{A}{L} \Delta P_l \quad (6)$$

where ' g ' refers to a gas phase, ' l ' refers to a liquid phase and the pressure drop along denotes by ' ΔP '. The value ' k_{rg} ' is gas effective permeability, and ' k_{rl} ' is effective liquid permeability. Every phase of the fluid is analogous to a homogenous system. The flow rate is proportional to the differential pressures and effective permeability and inversely proportional to the fluid phases' viscosity. The terms ' k_{rg} ' and ' k_{rl} ' are referred to as relative permeability.

Effective and relative permeabilities are functions of fluids that exist in a porous medium and porosity. Porosity can be measured directly or be calculated indirectly. The porous medium's flow characteristics are characterized by effective and relative permeability when saturated with an immiscible fluid phase. Therefore, the relative permeability of a porous medium depends on the saturation, so that relative permeability measurements require a precise saturation determination. By the presence of other phases, the flow of each phase is hindered. Therefore, the number of relative permeabilities is less than 1 (Bravo and Araujo, 2008). Theoretical aspects and measuring techniques of the relative permeability of sedimentary rocks were studied at the beginning of 1900s (Chalmers, J. Et.al, 1932; Muskat, M., 1937; Botset, H.G., 1940; Muskat, M., 1949; Wyckoff, R.D., and Botset, H.G., 1936).

Later, Wyckoff and Leverett (Wyckoff, R.D., and Botset, H.G., 1936; Leverett, M.C., 1939) discussed the gas-liquid mixtures flow through unconsolidated sands. Further experimental experiments were carried out, and laboratory measuring techniques were developed for the flow of two fluids through reservoir rocks by Richardson, Hafford, and other investigators (Osoba, J.S. *et al.*, 1951; Ceffen *et al.*, 1951; Caudle, B.H. *et al.*, 1951; Corey, A.T., 1957; Corey, A. T., 1954). There has been a growing interest in permeability testing on materials found near waste disposal sites, and research findings on relative permeability measurements have been reported to study the movement of typical pollutants (Faust, C. R., 1985).

This study aimed to design and build up a laboratory apparatus rig to determine the fluid flow capacity for two unconsolidated sand samples, using the Darcy equation. This test was essential since the understanding of flow capability can demonstrate how a porous medium makes fluids to flow through it and how effectively hydrocarbons would flow into the wellbore

2. MATERIALS AND METHODS:

2.1. Experimental Equipment Design

In the steady-state method, fluid flows at constant pressure and flow rate through the porous media until the differential pressure and saturation become constant. In the start-up of the research project during the apparatus's initiation process, equipment was not available in the research laboratory. Thus, tremendous effort and engineering thinking were made to build up the held equipment for the construction and building.

For limited cases, the sample of both fine sandstone and coarse sandstone were prepared by placing an amount of sandstone with different densities in a sieve shaker with different Mesh, used to separate sand granules according to its density, then the samples withdrawn from the sieve and placed after measuring in the 3" O.D. pipe core holder made from galvanized metal with 30 cm length. The core holder's ends are closed by glass wool to ensure no clarity of sands, and the filled sample is entirely squeezed to prevent the channeling phenomenon at high pressure. Water was injected into the core holder gradually, and it observed that the clay came out from the exiting side of the core holder due to its density less than the density of sand. A once through-flow system was designed and constructed to ensure studying flow capacity by water injection and

permeability under steady-state condition.

The flow system (Figure 1) consists of an air compressor with 16 maximum bar pressure as an air feeder, vacuum pump supplied from Kohler company removes gas molecules from a sealed volume. Pressure Regulator used to control the compressor pressure, core holder, water tank of 9-liter capacity. Valves and fittings are used to control fluid flowing inside the rig, different gauge pressure types, and float flow meter for measuring the exiting fluid.

2.2. Experimental Measurement Technique

In this research, the steady-state process method is used to determine the permeability and relative permeability of unconsolidated sands to water flow. Steady – State techniques for calculating permeability more commonly used, arising from the consistency of mathematical study based on Darcy's Equation and the assumption that saturation is directly calculated. The steady-state approaches provide accurate permeability results for two or three fluids simultaneously injected at constant pressure and rates. For these reasons, the course of the steady-state was used in this study. A standardized method includes the following determinations; liquid flow rate, gas flow rate, pressure gradient, and sample saturation. The fluid flow rate was calculated using the pressure gauges connected to the sample holder by measuring the pressure differences along with the core sample (Honarpour *et al.*, 1986; Honarpour *et al.*, 1988). The material saturation amounts can be calculated by dividing the volume of collected water in a cylinder by the core sample's total pore volume.

3. RESULTS AND DISCUSSION:

3.1. Core Sample Porosity Calculation

A rock's porosity is the proportion of the amount of space between the material's solid particles to the rock's total volume. Porosity measured as the rock's pore volume divided by its bulk volume as shown in Eq. 7 (Ghassan H. Ali *et al.*, 2019; Mohammed Y. Najmuldeen *et al.*, 2020):

$$\phi = \frac{V_p}{V_b} \quad (7)$$

The two cylindrical core samples' length and diameter are measured in inches using a Vernier caliper (Figure 2). The measurements were translated to centimeters (cm) [1 inch = 2.54 cm]. Core sample volume can be measured using

the cylinder volume by Eq. 8:

$$\text{Bulk Volume} = \frac{\pi}{4} D^2 L \quad (8)$$

Where:

D = diameter of the core sample

L = length of the core sample

$\pi = 3.14$

The core sample's pore volume was evaluated from subtracting the amount of water in (remaining water in the tank, valves, pipes, and amount of water out) from the original water inside to the tank. Finally, each core sample's porosity was calculated from the rock pore volume divided by its amount of bulk using Equation (7). The core specifications and porosity results are tabulated in Table 1.

3.2. Absolute Permeability Determination

The permeability measuring technique consisted of injecting gas or a liquid into the unconsolidated sand core sample at a steady rate (Yahya J. Tawfeeq *et al.*, 2020). Figure 1 displays the schematic diagram of the designed equipment. A known weight of the selected grain size of unconsolidated sand was filled in the sample container, which is known as a core holder. Each part of the volume of sand was tamped carefully by a rod. The laboratory procedure started with operating the vacuum pressure to empty the system from the air. During the evacuation, the system from air the two end valves must close, while inside valves opened. The pressure level will be achieved by changing the pressure control valve that wanted to supply to the system. Turn the valve gradually such that the pressure provided is directed into the cell-containing water and a sufficient flow produced into the core. We wait until the cylinder was filled to a readable level with liquid, the cylinder removed, and the timer stopped simultaneously. Read the amount of water that collects and record all data: volume, the time elapsed, and inlet pressure. Different flow rates measured for different pressure gradient, at viscose flow, the results for core sample #1 one, and sample #2 are shown in Tables 2 and 3.

As the flow rate increases, the pressure difference also increased. There was a direct correlation and relationship between the flow rate and the pressure difference. This relationship can be seen from Tables 3 and 4 when the flow rate

was 0.271 cm³/sec, and the pressure gradient was 1.283 atm. Also, when the flow rate increased to 0.469 cm³/s, the pressure gradient increased to 1.703 atm, resulting in a straight-line plot of pressure gradient against the flow, as shown in Figures 3 and 4. Darcy Equation could be used for measuring the core plug's absolute permeability through Eq. 9 and 10:

$$q = \frac{A K \Delta p}{\mu L} \quad (9)$$

and

$$q = \frac{Q}{\Delta t} \quad (10)$$

Where: "q" is the water flow rate cm³/sec; "Q" is the collected water volume during a specific time (sec); "ΔP" is the pressure differential (atm); "A" is cross-section area cm²; "L" is core sample length cm.

First, we find (ΔP/L), where L is the core length in cm, and q/A, where A= cross-sectional area of the core in cm²; the results are given in Table 4. Then plot ΔP/L versus (q/A) will provide a straight line with slope (Eq. 11);

$$\text{slope} = \frac{K}{\mu} \quad (11)$$

Figures 3 and 4 show that the linear best fit through all experimental data-points will give a slope, from which the permeability (K) calculated. The results of computed slope and absolute permeability are given in Table 5.

3.3. Effective / Relative Permeability and Fluid Saturation Determination

There are three primary types of permeability: absolute, relative, and effective. Phase (i) relative permeability could be expressed by Eq. 12:

$$K_{ri} = \frac{K_i}{K} \quad (12)$$

Where:

K_{ri} is the relative permeability of phase i (i = oil, water, and gas)

K_i is the effective permeability of phase i (i = oil, water, and gas)

k is the permeability of the porous medium in single-phase flow, i.e., the absolute permeability.

Muskat *et al.* (1937) (Olivier Darrigol, 2005), based on Darcy's law showed that "the volumetric flow rate can be written individually for each fluid/phase flowing into the pore" as shown in Eq 13:

$$Q_i = K k_{ri} \left(\frac{A}{\mu i} \right) \frac{\Delta P_i}{L} \quad (13)$$

The laboratory technique started applied to the sample one fluid phase (water) and changed this phase's flow rate until the sample was 100 percent filled with water. Regulators and pressure gauges attached to the system were responsible for assessing and changing water flow rates. A second phase injection, which was gas, began at a low rate, and the first phase flow significantly decreased. This technique maintained the differential pressure constant in the system. We wait until the cylinder filled up to a readable level with the water, remove the cylinder and simultaneously stop the timer. Read the amount of water that collects and record all of the data: distance, the time elapsed, and inlet pressure. The differential pressure was measured using the pressure gauges attached to the system. The effective permeability of water is calculated by Darcy equation using Equation (14) while the relative permeability of water computed using Equation (16) as;

$$K_w = \frac{q_w \mu_w L}{A \Delta P} \quad (14)$$

With

$$q_w = \frac{Q_w}{\Delta t} \quad (15)$$

$$K_{rw} = \frac{K_w}{K} \quad (16)$$

Where: "q_w" is the water flow rate cm³/sec; "Q_w" is the water volume collected in water graduated cylinder during a specific time (sec); "ΔP" is the pressure differential across the core (atm); "A" is cross-section área (cm²); "L" is core sample length cm; "μ_w" is the viscosity of water cp; "K_{rw}" is the relative permeability of water; "K_w" is the effective permeability of water; "K" is the absolute or total permeability of core sample

The results of the effective and relative permeability of water tabulated in Table 6. Relative permeability measurements require accurate determination of the saturation (Honarpour and Mahmud, 1988). The fluid saturation is given by Eq. 17:

$$S_f = \frac{V_f}{V_p} \quad (17)$$

Where: "S_f" is fluid saturation; "V_f" is fluid volume, and "V_p" is total pore volume. Saturation is a concept used to describe relative fluid concentrations in a porous medium; as the saturation varies over time, the total saturation value for two fluids is equal to one. Saturation and permeability are both affected by the porosity of the rock sample. Water saturation calculated by dividing the collected water volume in a cylinder by total core sample pore volume as shown in Eq. 18:

$$S_w = \frac{V_w}{V_p} \quad (18)$$

Where S_w is the water saturation, V_w is the volume of water accumulated in the graduated cylinder in cm³ and V_p is the total pore volume in cm³. The results of water saturation are tabulated in Table 6.

3.4. Present Study Limitations

In this experiment, the following errors may have arisen. The packed sand layer may not characterize the rock reservoir as reservoir rocks are not homogeneous, but heterogeneous. There could be a willingness to examine the best portions of sand medium and an inability to read the gages correctly. The sand medium's permeability altered whether it was collected from the original sample or if it was washed and packed.

4. CONCLUSIONS:

When preparing the sample, if the sample container is filled with a more significant amount of sand, the permeability will decrease, requiring high pressure for fluid flowing within the sample. The PVC plastic pipes used to prepare some equipment parts cannot withstand high pressure greater than 10 bar. A metallic material was used for the sample cover to withstand high pressure during the test. Distilled water is preferable to use during the experiment to avoid sample damage, leading to an error in calculations. The medium relative permeability depends on the saturation of the various phases. A proportional relationship exists between flow rate and pressure gradient during fluid flow through a porous medium. The relation between the flow rate, viscosity, sample length of rock bed, permeability, the sample size of the cross-sectional bed of rock, and pressure

gradient are proportional. To assess absolute permeability, the pores media must be 100% saturated with the specific fluid type. Absolute permeability does not depend on fluid characteristics but only on media properties.

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Figure 1. The schematic diagram of the designed apparatus.

Figure 2. Sketch of Core Sample

Figure 3. Pressure Gradient Vs. Flow Rate for Sample # 1

Figure 4. Pressure Gradient Against Flow Rate for Sample # 2

Table 1. Core Samples Dimensions and Calculated Porosity Results

	Core Sample # 1	Core Sample # 2
Lithology	Coarse sand	Fine sand
Grain Size (μm)	500	125
Core Diameter (cm)	7.75	5.3
Cross Section Area (cm^2)	47.173	22.062
Core Length (cm)	26.5	30
Pore Volume (cm^3)	359	102
Bulk Volume (cm^3)	1250	661.855
Core Porosity %	28.72	15.41

Table 2. Results of Flow rate vs. Pressure for Core Sample # 1

Test N°.	Δp (atm)	Volume of Liquid collected Q (cm^3)	Duration, Δt (sec)	Flow rate q (cm^3/sec)
1	0.9743	250	239.43	1.044
2	1.9615	250	154.63	1.616
3	2.9487	250	70.1	3.571
4	3.9358	250	54.14	4.617
5	4.4294	250	47.58	5.254
6	4.923	250	45.91	5.445
7	5.4166	250	39.82	6.278
8	5.9102	250	36.55	6.839
9	6.4038	250	30.36	8.234

Table 3. Results of Flow rate vs. Pressure for Core Sample # 2

Test N°.	Δp (atm)	Volume of Liquid collected Q (cm^3)	Duration, Δt (sec)	Flow rate q (cm^3/sec)
1	1.283	150	553.71	0.271
2	1.703	150	320.03	0.469
3	2.124	150	228.72	0.656
4	4.235	150	125.32	1.197
5	4.836	150	97.65	1.536
6	6.12	150	70.63	2.124

Table 4. Pressure Gradient Per core length and Flow Rate Per Core Area Results for Two Samples

Test N°.	Sample # 1		Sample # 2	
	q/A	$\Delta p/L$	q/A	$\Delta p/L$
1	0.022131	0.036766	0.01228	0.042767
2	0.034257	0.074019	0.021247	0.056767
3	0.0757	0.111272	0.029728	0.0708
4	0.097874	0.148521	0.054257	0.141167
5	0.111377	0.167147	0.069628	0.1612
6	0.115426	0.185774	0.096265	0.204
7	0.133085	0.2044		
8	0.144977	0.223026		
9	0.174549	0.241653		

Table 5. Determined Slope and Absolute Permeability Results for Two Samples

Core	Fluid Viscosity cp	Calculated Slope	Absolute Permeability Darcy
Core Sample # 1	1	0.7174	0.7174
Core Sample # 1	1	0.4886	0.4886

Table 6. Effective Permeability, Relative Permeability and Water Saturation Results for Two Samples

Test N°.	Core Sample # 1			Core Sample # 2		
	K _{eff} (Darcy)	K _{rw}	Sw%	K _{eff} (Darcy)	K _{rw}	Sw%
1	0.6351	1	100	0.01486	1	100
2	0.6034	0.9501	95	0.01373	0.924	91.23
3	0.5349	0.8422	90	0.01064	0.716	72.07
4	0.4048	0.6374	80.45	0.00814	0.548	57.36
5	0.1959	0.3085	75.98	0.005734	0.3858	41.57
6	0.1287	0.2026	69.83	0.003477	0.2339	27.21
7	0.0486	0.0765	65.36			
8	0.0382	0.0601	56.797			
9	0.0156	0.0246	49.91			
10	0.0044	0.0069	45.44			
11	0.0011	0.0017	43.57			
12	0.0005	0.0008	34.26			