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COMPARISON BETWEEN KLINKENBERG-CORRECTED AND WATER PERMEABILITY: A REVIEW

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ABSTRACT

Absolute liquid permeability value is required as an input for dynamic model initialization for reservoir simulation studies. Industry standard practice is to obtain either Klinkenberg-corrected permeability values or liquid permeability values. Klinkenberg-corrected permeability values are obtained from gas permeability measurement and corrected for Klinkenberg effect, on the other hand liquid permeability value is obtained from laboratory measurement of brine permeability. The theoretical assumption is that both of these permeability measurement should produce similar values but experimental measurements show that Klinkenberg-corrected permeability values are usually higher than water permeability values. The amount of time and cost spend on determining these two values for each core sample can be reduced if a correlation is developed describing the relationship between these two values of permeability for specific region. Water permeability values of specific region can be predicted using the established correlation thus saving time and cost to determine the value of permeability experimentally. There are handful of studies regarding the correlation between Klinkenberg-corrected and water permeability however most of the studies are region-specific and narrow. Furthermore the factors for the difference between Klinkenberg-corrected and water permeability values are still unclear and without evident proof. This article provides a review of this specialized area of study from the early to recent contributions on the relationship between Klinkenberg-corrected and water permeability values and its factors.

Keywords: klinkenberg-corrected permeability, water permeability, fines migration, pore throat radius.

INTRODUCTION

Absolute liquid permeability value is important particularly in establishing dynamic model for any reservoir studies using simulation modelling software. Normally the industry practice is either to correct gas permeability values to Klinkenberg-corrected permeability or use any liquid permeability data using brine as pore fluid [1, 2]. Thus if either value of permeability can be used as liquid permeability, then theoretically both the permeability values should be comparable, however experimental values of Klinkenberg-corrected permeability is usually higher than water permeability values.

These observations are in line with studies that had been conducted by [1, 3-11]. Due to the differences in permeability values, a lot of time and cost were spent on measuring both permeability values usually for the same reason. Thus, authors such as [1, 3, 4, 6, 10-15] proposed a solution by developing a correlation between these two values of permeability for specific regions and area of study.

Many authors have explained the reason for the difference in value of Klinkenberg-corrected permeability and water permeability which are the wide range of factors influencing the value of water permeability of core samples which include clay swelling, rehydration of unreacted minerals, dissolution/precipitation of matrix, fines migration and also water adhesion to the smallest pores of the matrix and many others [3, 5, 7-10]. This is also supported by [16] whom fundamentally stated that whenever the physical and chemical equilibrium between the rock forming minerals and pore fluids are disturbed, there will be tendency for formation damage to occur. Reference [16] also added that the formation damage mechanism involves complex physicochemical and hydrodynamic processes that attributed from different sources.

Until today, and despite the many publications on this topic, only a few general compilations exist about all the factors that are known to control the disparity between Klinkenberg-corrected and water permeability values. This review attempts to fill this gap, by proposing a comprehensive review of this specialized literature, from the early and recent contributions in developing correlations between Klinkenberg-corrected and water permeability values, with emphasis on the recent studies regarding the factors affecting the disparity between Klinkenberg-corrected and water permeability values.

Klinkenberg effect and gas corrected permeability

Gas flow in porous media is not similar to water or liquid flow due to the fact that gas is highly compressible and the effective permeability is dependent on pressure [1]. Gas permeability is basically the ability of injected gas to flow through the pore spaces of the rock sample. Gas permeability equation is as follows:

$$k_a = 2000\ (L/A)\ \mu\ Q\ (P_{atm}/(P_o^2 - P_i^2)) \quad (1)$$

Where,

k_a = air permeability, md
P_{atm} = atmospheric pressure, atm
P_i = upstream pressure, atm
P_o = outlet pressure, atm
L = length, cm
μ = air viscosity, cP
Q = gas flow rate at atmospheric pressure, cm^3/sec
A = cross-sectional area, cm^2

This equation applies for steady-state permeability measurement using non-reactive gases such as nitrogen and helium. The assumptions are the same as assumptions for Darcy's Law. Gas permeability measured in laboratory usually is subjected to Klinkenberg effect especially in low permeability samples which will result in overestimation of the value of gas permeability. This theory was first established by [17] after discovering the observation by [18] that there was large difference between air permeability and water permeability values [19]. Reference [17] defined Klinkenberg effect as the effect that occurs when the mean free path of gas molecules in any porous media approaches the pore dimension. This phenomenon will lead to more frequent collision between gas molecules and the pore wall than the collisions between gas molecules which reduces viscous drag, thus enhancing gas slip flow and increasing the gas permeability values [2, 9, 20, 21]. Thus the value of gas permeability should be corrected to a more representative value at infinite differential pore pressure which is called Klinkenberg-corrected permeability or also known as liquid permeability [20]. Since at infinite differential pore pressure gas flows as liquid-like fluid, theory suggests that Klinkenberg-corrected permeability or liquid permeability of a particular core sample should be similar as the water permeability value. This is supported by [9-11, 19] which stated that the permeability of a sample should be independent of its pore fluid, thus the values of gas permeability and water permeability should be the same within the experimental error. Reference [17] concluded that effective gas permeability at a given pressure is:

$$k_g = k_\infty (1 + b / P_m) \quad (2)$$

Where:

k_g = gas permeability
k_∞ = permeability at infinite pressure or liquid permeability
b = gas slippage factor
P_m = average pore pressure

The theory is that the mean free path is inversely proportional to the mean pressure. At lower mean pressure, the mean free path increases thus enhancing the slippage and simultaneously increasing the permeability [17]. On the other hand when mean pressure increases, the mean free path decreases and reducing the gas slip flow and thus reducing the permeability [17]. Reference [21] said that [22] concluded that b reduces as permeability increases based on his study on 100 core plugs with permeability ranging from 0.01mD to 1000mD,

$$b \; \alpha \; k_\infty^{-0.36} \quad (3)$$

Steady-state method is conventional method in laboratory gas permeability measurement, however, in low permeability samples where Klinkenberg effect is much more significant, the time needed to reach steady-state phase is too long added also by the relatively slower flow rate used [23]. Reference [23] stated that the time required to reach steady-state for a 1-Dimensional flow experiment is proportional to the square of the sample length and inversely proportional to the intrinsic permeability of the sample. In order to measure the intrinsic permeability, k and the Klinkenberg constant, b will require the same experiment is repeated for different mean pressure levels. Thus toovercome these constraints to measure the Klinkenberg parameters, unsteady-state method is preferred since it is fast, does not need to reach steady-state phase and lastly single experiment is sufficient to estimate the coefficients k and b [23].

Difference between Klinkenberg-corrected and water permeability

Water permeability is the absolute permeability of the rock having water as its pore fluid. References [9-11] states that the permeability of a porous and permeable medium is independent of the pore fluid. Thus by this theory water permeability values and also gas permeability values should be the same. However experimental studies usually shows differences in Klinkenberg-corrected permeability and water permeability values. This observation is in line with studies conducted by [1, 3, 4, 6, 10-15].

All of the studies regarding subject matter reported that water permeability result are mostly lower than the Klinkenberg-corrected permeability. Although there are numerous reasons for the difference in value of Klinkenberg-corrected permeability and water permeability values as reported by many authors, the most common reasons are the effect of formation damage due to adhesion of water films on pore walls which causes thinning of pore throat diameter and reducing water permeability value [3, 4, 6, 11] and effect of fines migration due to presence of clay particles [12, 14]. Based on previous studies it is obvious that clay swelling and fines migration can cause significant formation damage to the reservoir rocks causing reduction in water permeability thus leading to decline in production and reservoir quality.

Studies such as [3, 4, 6, 11] argued that the reason for the difference between Klinkenberg-corrected and water permeability in their study is due to the inability of water to flow through small pores and micro-cracks compared to inert gases. The ability of inert gases to flow through the double network system (matrix + naturally induced fractures) will cause the gas to cover more area of the pore system to have higher permeability value [4, 11]. However, water has the ability to chemically react with clay particles in the core samples which in turn will form layer of clay bound water on the pore throat and micro-cracks surfaces which will reduce the effective radius of these pore system and impede flow of water in the matrix system [6, 11]. However [3, 4] argued that the values of water permeability were still lower than Klinkenberg-corrected permeability measured from their samples which contains less than 0.1% of clay compositions. Reference [3] stated that obviously the difference in values between Klinkenberg-corrected and water permeability of their samples were not due to reaction of water with clay

particles rather due to steady state flow which will form thin water films around the grain matrix through fluid storage and mechanical coupling. Reference [3] proved that the water films were visible at high curvature contact points, inter-grain separations and the grain surfaces. This observation is also supported by [4] that stated that the nature of the samples which are tortuous, kinked, and also the rough nature of the micro-cracks which allows the adsorption of water to reduce the water permeability. Reference [4] also added that the adsorbed water molecules need not obstruct the entire length of a micro-crack, but only a small section – perhaps a particularly rough-walled section or at a tight bend or kink and it will give great impact towards permeability reduction by impeding the flow of water.

Reference [24] stated that clay particles specifically can be divided into swelling clays (smectite group) and non-swelling clays (kaolinite group). Swelling clays by its name suggest that when comes into contact with water will tend to swell and on the other hand non-swelling clays will experience dispersion and migration under critical flow rate [24]. Reference [24] in his experiment on the effects of presence of clay particles on permeability reduction also proved that all clay coated samples experience 10% to 40% of permeability reduction compared to uncoated sample when the samples are injected with water. The experiment conducted by [24] observed that the swelling clay (smectite group) coated sample only experience initial clay swelling without any further damage however, the non-swelling clay (kaolinite group) coated sample experienced damage over time due to fines migration. The study conducted by [24] proved the ability of different type of clay content on reducing water permeability values which can cause differences in between water permeability and Klinkenberg-corrected permeability values of core samples. Studies such as [3, 4, 6, 10, 11] have also discussed regarding the effect of overburden pressure towards permeability change. All studies have concluded that overburden pressure will cause reduction in permeability of a sample especially in samples with lower permeability up to 60% reduction. However, [6] stated that further research has to be conducted on the reasons for reduction in permeability due to stress increase.

References [25] fundamentally stated that fines migration happen due to the shear force of injected fluid leading to dispersion and migration of clay particles downstream. However there are some particles that are adsorbed on the pore surfaces. Thus [16, 25] concluded that the combined impacts of disturbance of chemical and physical equilibrium between rock forming minerals and pore fluids contribute to the reduction of water permeability values. The complex reaction of both physicochemical and hydrodynamic processes in the core samples leads to the occurrence of formation damage, thus the severity of the permeability impairment can only be quantified by the combined impacts of foreign fines invasion, in-situ fines mobilization, dissolution/precipitation of matrix and also clay swelling [5, 16]. Furthermore [16] has also categorized the factors affecting formation damage which are:

A) Type, morphology and location of resident clay minerals

B) In-situ extraneous fluids composition

C) Well development and reservoir exploitation practices

Fines migration happens when the lifting and drag forces denoted by Fl and FD respectively, detach the particle from the surface of the rock exceeding the electrostatic, Fe, and gravitational forces, Fg, which holds the particle in place and attached to the surface as shown in Figure-1 [26, 27].

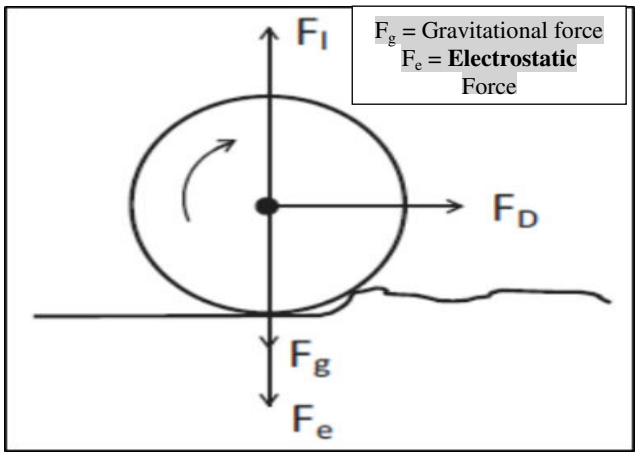

Figure-1. Attaching and Detaching Force Balance on a Particle [10].

The force balance between detaching and attaching forces determine the mechanical equilibrium of the particles. When the detaching torque is greater than the attaching torque, the particles will be detached (fines migration occur), otherwise the particles will stay attached at the rock surface [26, 27]. Fines migration becomes a problem and damage the formation when the earlier detached particles migrate and plug the narrow pore throats due to retention by size exclusion resulting in reduction in permeability. Fines migration can also be a problem when the small fines that have been detached previously reach a larger pore throats at the same time and compete for passage thus leading to bridging and sedimentation at the pore throat thus reducing the permeability [26].

Fines migration happen due to injection rate exceeding the critical flow rate, decrease in salinity, decrease in concentration of dipolar ions which are then substituted by unipolar ions (ionic strength), gradual change in salinity and pH, and also due to overburden pressure [16, 28, 29]. Reference [16] added that the association of these factors leads to the deflocculation of the in-situ clay particles as fines migrate thus plugging the flow paths. This theory is also supported by [29] but in

terms of pressure gradient where they stated that the clay particles can move and disperse unavoidably when the shear force exerted by the pressure gradient is greater than the critical pressure gradient causing pervasive micro-fracturing including numeruous intra- and trans-granular micro-cracks, collapse of weak minerals and grain size reduction.

Studies have also shown that salinity of injected water with respect to formation water is important during water injection into clay-containing core samples as it may cause formation damage due to clay swelling when the clay comes into contact with less saline water than the original formation water [8, 24, 28, 30]. The critical salinity study for clay swelling by [7] concluded that the critical salinity that will start to cause significant clay swelling is very low compared to the salinity of the formation water. The SEM analysis of pre and post-test showed that the authigenic kaolinite and the mixed layer (illite-smectite) clay remained its morphology without any significant changes. However to further validate the clay swelling effect, the same core sample is injected with fresh water (50 ppm). The results still showed that the mixed layer (illite-smectite) remained intact without any significant damage due to clay swelling. This observation is against the claim by [8, 24, 28, 30] that clay has higher tendency of swelling when comes into contact with lower salinity water, thus all of these studies injected fresh water to maximize the effect of clay swelling.

Reference [8] proved that the brine or injected water salinity have significant changes in clay swelling effect. The study by [8] used three different type of injected water, 1) formation brine, 2) KCl brine, and also 3) distilled water. All three types of injected water showed significant permeability reduction however comparing formation brine and distilled water injection; distilled water injection caused a more severe permeability reduction. On a different note, [24] also stated that swelling type clays have the tendency of only swelling instantaneously after coming into contact with water and it also has the tendency to disperse. Reference [24] also concluded that the effect of clay swelling strongly depends on the matrix grain size where samples with higher porosity will not have significant changes in permeability reduction due to clay swelling. Thus clay swelling will have a more profound effect on lower porosity samples [24].

Reference [27] conducted experiment on the effect of decrease in salinity on the fines migration problem. Reference [27] detected the presence of fines in the core effluent collected during injection of different salinity of water and the observation suggests that presence of fines in the core effluent indicates fines mobilization which later damage the permeability. The reduction in water salinity showed that permability to water decline at high water saturations where fines migration happens due to the larger rock surface accessible to water causing significant permeability decline [27]. However, the permeability reduction is seriously significant only during the injection of very low salinity water (less than 0.05 wt%) which is followed by significant fines production in the core effluent [27]. Reference [27] injected back the original brine with (3 wt%) at the end of the experiment to see if the permeability is restored back but the permeability did not turn back to its original value suggesting that clay swelling is not the reason for the reduction in permeability. Thus [27] concluded that the presence of fines on the core effluent and the permeability is not restored back after initial salinity water is injected at the end of experiment prove that the permeability reduction is only due to fines migration. Reference [26] also supported this observation by quoting that salinity change followed by high flow rate and sharp changes in salinity could be the causes of mobilization and bridging of fines at the pore throat. Reference [16] added that mixing of waters (formation water and injected water) from different sources can incur serious fines production problems especially when sulfate ions containing waters injected to a barium ions containing formation waters.

The K_∞ and K_W correlation

Although numerous studies have been conducted previously such as by [1, 3, 4, 6, 11-15] to find a solution for this problem by producing correlations between gas permeability and water permeability values, however most of the studies are based on sandstone formations and very few selective correlations are available for carbonate formations such as the correlation produced by [1] on Shiuaba carbonate formation in Oman, [11] on dolomite from Zelatowa quarry, Poland and [14] that produced permeability correlation for selected carbonates. References [1, 11, 31] argued that the correlation established based on sandstone samples cannot be applied on carbonate formations due to the complexity and uncertainty of pore geometry of carbonate rocks that ranges from big and interconnected pore system to micro pore structure which only contains intra granular pores or even irregular pore system such as vugs and pore spaces created from grain dissolution. Reference [1] conducted experimental measurement of water permeability of 80 carbonate core samples from Upper and Lower Shuaiba formations and compared its water permeability values to its already measured Klinkenberg-corrected permeability values. Reference [1] used formation water (brine) prepared in laboratory as injected water at 4 different flow rate to obtain an average value of water permeability for the samples. Before inserting the core samples inside the core holder for water injection, the core samples are saturated with the brine using vacuum and high pressure saturation to prevent any trapped gas or air inside the pore spaces.

The Klinkenberg-corrected permeability and water permeability values are then plotted on a log-log graph and [1] used power regression to produce the relationship. The results showed a proportional relationship where water permeability is lower than Klinkenberg-corrected permeability by a factor of 0.75 to 0.99. After removing the one outlier, the relationship was established as shown in Figure-2 below:

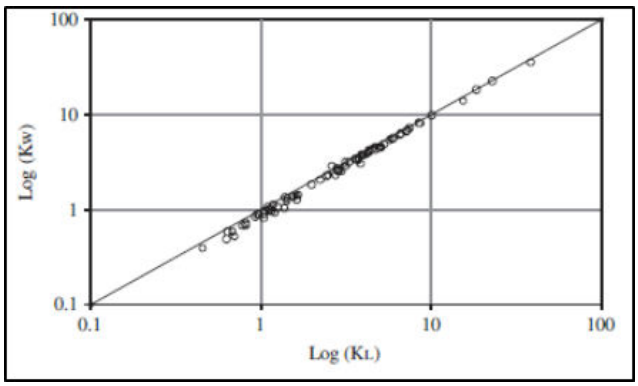

Figure-2. Log-log graph of water permeability against liquid permeability [1].

$$k_w = 0.864\ k_\infty^{1.039} \quad (4)$$

In order to prove the validity of the correlation produced, [1] have used 10 measured core samples and 35 previously available data from Lower and Upper Shuaiba formations for the validation purpose. Upon validating the data, negligible differences of 0.4% were observed thus proving that this correlation is applicable for carbonate formations in both Upper and Lower Shuaiba formations.

Similarly, study by [3] on 30 Fontainebleau sandstone samples which were composed of 99% quartz shows that all the measured Klinkenberg-corrected permeability were higher than water permeability as shown in Figure-3 below.

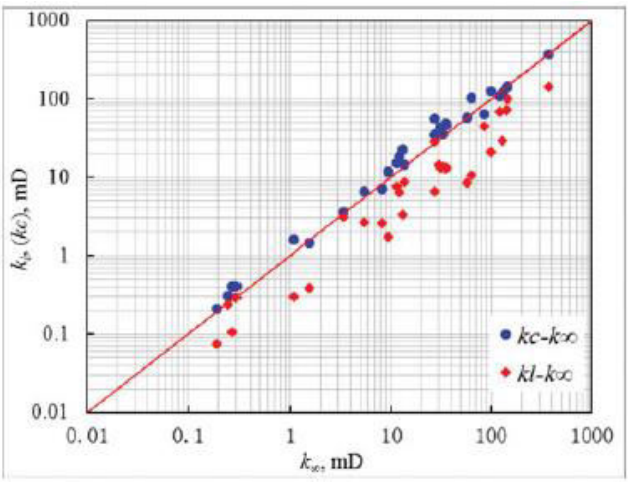

Figure-3. Log-log graph of water permeability against liquid permeability [3].

All studies mentioned above have a similar but not exactly, experimental procedures and obtained similar results which is the straight line relationship between Klinkenberg-corrected permeability and water permeability values when plotted on a log-log scale. However, the coverage of this specialized study does not cover a wide range of areas especially in the Malay basin. As far as the author's knowledge, there are no studies dedicated regarding the correlation between Klinkenberg-corrected and water permeability for Malay basin samples and many other regions which yet to be explored.

CONCLUSIONS

The study regarding relationship between Klinkenberg-corrected and water permeability values are still at the early stage where there are only few studies which are focused on specific and individual region of study. However, almost all studies reported showed similar trend in terms of correlation between Klinkenberg-corrected permeability and water permeability values.

Although the trend of the correlation for all these studies are similar, however the discussion of the factors for the difference between Klinkenberg-corrected and water permeability values differ between authors. Some of the earlier authors did not discuss at length regarding the factors affecting the difference between the Klinkenberg-corrected and water permeability values. Earlier authors usually attribute the difference in permeability values to formation damage due to presence of clay particles. However, recent studies have included the discussion regarding the factors for the permeability difference such as effect of pore pressure, fines migration and effect of pore throat radius.

Although there are studies regarding this specialized area of study, all of them are very region specific and narrow. Furthermore, the discussion on the factors for the difference between Klinkenberg-corrected and water permeability values are still unclear with concrete proofs. Thus more studies like this should be conducted on other regions which require further understanding of permeability of the region. Studies regarding the factors for the difference between Klinkenberg-corrected and water permeability should be conducted at a much deeper level to gain better understanding.

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