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Support of Inertial Fluid Flow in Porous Media to CO_2 Geological Sequestration Surveillance Program

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ABSTRACT
This study presents a new vision that may enhance the MMV (measuring, monitoring and verification) program of the In Salah geological carbon capture and storage project. It demonstrates: 1). the importance of non-Darcy flow coefficient in characterizing Krechba carboniferous reservoir which is a gas reservoir and CO_2 fate in the saline aquifer interval, 2). the verification if CO_2 well injectors were drilled in accurate zones in the field on the basis of non-Darcy flow coefficient distribution and well performance, and 3). the prediction of where new injectors can be drilled for future CCS (Carbon capture and storage) projects.
What has been done in the domain of non-linear fluid flow in porous media is critically reviewed. Non-Darcy flow coefficient is obtained by laboratory core analysis conducted under unsteady state conditions on eighty-four (84) reservoir core samples obtained from different fields in the In Salah region.
A general scale of non-Darcy flow coefficient versus permeability is developed based on the reference base-line obtained from inertial flow through metallic porous media. This novel scale is used to: 1) classify the In Salah reservoirs in term of heterogeneity; 2) establish an iso-non-Darcy flow coefficient map for improving CO_2injectivity performance.
These findings could have an important impact on reducing the cost of well deliverability maintenance such as: location, perforation and stimulation jobs, and hence considerable benefit to the CO_2 storage industry.

KEYWORDS: Non-Darcy flow coefficient; CCS project; heterogeneity scale

1. INTRODUCTION

Human activities are responsible for 36% increase of anthropogenic CO_2 in the atmosphere from the beginning of the industrial era, 1800. The sources of these emissions are: the combustion from fossil fuel energy (coal, petroleum and natural gas), steel and cement industries, deforestation … (Martin et al., 2008). The massive GHG increase, particularly CO_2, has caused climate disturbance followed by devastating natural consequences. The geological sequestration of CO_2, called Carbon Capture and Storage (CCS) is considered as one of the most efficient solutions that contribute to overcome climate change disequilibrium.
It may contribute to the reduction of: 1). GHG emissions: approximately 20 to 30% of CO_2 emission at world level (BIP, 2009; Qurkis, 2009). 2). The rise of atmospheric temperature: To limit the increase of 2°C by 2050, the emission of CO_2 in 2000, evaluated by Tier 1 sectoral approach to be 23.5Gt (IEA

Statistics, 2011), should be reduced at 85%; otherwise, the temperature will increase by 4 to 7°C (Qurkis, 2009).

If CO_2 emissions remain at the present rate, 407 million tons per annum (407MMTPA) (Deghmoum and Baddari, 2012)., the average oceanic level may surpass 1m and reach 2m at the end of this century (Allison et al., 2009). In addition, the average pH of surface oceanic that is now near 8.1 has already decreased by 0.1unit from the beginning of industrial era. It may decrease also by 0.2 to 0.4unit at the end of this century (Martin et al., 2008).

From these predictions, it is easy to imagine the atrocious consequences that will occur: 1). the total or the partial elimination of certain countries such as: Fiji, Tuvalu, Maldives (first countries to ratify Kyoto protocol in Sept-Dec 1998 (UNFCCC, 2009), 2).Coastal erosion of all continents, 3). Strong droughts, 4).Tornadoes in series followed by huge flooding, 5). Terrestrial and aquatic fauna and flora damage, 6). Political conflicts on drinking water, 7). Epizootic diseases. Because of these consequences, many initiatives are focusing on the encouragement of general deployment of GHG abatement projects among them "geological sequestration". The geological formations are deep briny formations, mature oil and gas reservoirs and unmineable coal seams. CCS pilot sites have been launched in many countries and directives as well as regulations for the orientation and the development of this emerging technology are now in the way of elaboration.

The surveillance program to support this technology regroups multidisciplinary analyses and data collection such as:: geology, hydrogeology, reservoir engineering, microbiology, geomechanics, fluid mechanics, geochemistry, seismic 2D, 3D and 4D, simulation and modeling, non-radioactive tracers, injector and producer wells, tiltmeter, satellite imaging…The success of such program to solve sequestration challenges, like technical feasibility, cost-effective and safety at long term, may have an important influence on the acceleration of the deployment of large scale CCS projects. We focus in this study on the support of inertial fluid flow through porous media to the CO2 sequestration surveillance program. For this reason, a critical review in this domain will be given.

Fluid flow and mass transfer in porous media particularly under non-Darcy flow regime has received increased attention during the past three decades. This is due to the importance of this research area in many engineering applications (Magyari et al., 2005), including oil and gas exploration and production, carbon sequestration, nuclear waste disposal in geological formations (Ho and Webb, 2006), environmentally related studies on the management and remediation of leaking underground storage tanks (USTs) (Ong, 2006), groundwater contamination by volatile organic compounds (VOCs), thermal insulation, electronics cooling and packed bed chemical reactors (Khanafer and Vafai, 2006), pertinent biological areas such as the modeling of blood perfusion, heat and flow in human tissues, diffusion in brain tissues, diffusion during tissue generation process, (Vafai, 2005).…

Understanding the fundamental mechanisms and processes of fluid flow in porous media allows models to be used to evaluate and to optimize the performance and the design of the above complex systems (Ho and Webb, 2006).

In this study, the importance of the use of non-Darcy flow coefficient, to overcome certain challenges in the domain of environmental issue, is highlighted. The fundamental effort is to assess inertial flow through cylindrical core samples which is carried out in Core Analysis Laboratory of Sonatrach Company located in Boumerdes, Algeria. The obtained laboratory data are projected afterward for CO2 sequestration development project using well test analysis and log data combination.

2. LITERATURE REVIEW AND THEORETICAL BACKGROUND

Non-Darcy flow in porous media has been studied in depth for various geometrical configurations and boundary conditions. Although, significant progress has been made, it was stated from literature review conducted on different application areas of fluid mechanics in porous media that there is an enormous discord between researchers' point of view. The lack of consensus can be observed on the definition of non-Darcy Coefficient, its dependency with the length of the porous medium and the type of fluid, the definition of length scale in Reynolds number, and the range of flow regimes according to Reynolds number. In this section, we will discuss briefly these aspects and we will focus on the determination of non-Darcy flow coefficient.

Non-Darcy flow coefficient has been called: turbulence factor, coefficient of inertial resistance, velocity coefficient, Forchheimer coefficient, inertial coefficient, and beta (β) factor (Dacun and Engler 2001).

Because of complicated architecture of any naturally occurring porous medium in term of random pore size distribution and shapes, the simultaneous of two more flow regimes may coexist. Even though, fluid flow in porous media can be classified in different categories, the describing of the transition rates between simultaneous of two modes of flow is too complex, which may lead to ambiguity and lack of consensus. For this reason, it was suggested to use viscous Darcy flow to describe the flow regime observed at low flow rates, and for high velocity flow to use "quadratic Darcy flow" (Firoozabadi and Katz, 1979), because viscous flow theoretically occurs when the flow rate is infinitely small. Even this suggestion may not be clear because other flow regimes may concurrently occur at low flow rates.

In general, flow regimes in porous media that can be revealed (Bear, 1972; Scheidegger, 1974) are: (a) diffusional flow, (b) molecular slip flow, (c) viscous flow, (d) visco-inertial flow, (e) inertial dominated flow, (f) inertial/turbulence transitional region, (g) turbulent flow.

Each of the above regimes has its appropriate equations and derivatives to model and to describe flow mechanism, mass transport or heat transfer in porous media. In this study, we will target the transition from viscous (linear) to inertial dominated (nonlinear) flow, usually known as the 'non-Darcy' flow region.

Darcy's pioneering experimental work (Darcy, 1856) is well recognized as the key factor in modeling purely viscous fluid flow through a porous medium including clarification of several important physical phenomena. This flow is characterized by linear proportionality between pressure gradient and flow rate. However, in certain circumstances such as low pressure gradient or high velocity, this law may lead to erroneous results.

Klinkenberg (1941) showed that the permeability evaluated by gas at low pressure gradient using Darcy's law cannot be determined. This is due to gas molecules are affected by "Slippage" which accelerates the flow of gas when the free mean path of the gas approaches the dimension of the pore, because under these conditions some of the random kinetic energy of the gas is transferred to movement of the gas molecule through the pore, or slippage at the pore walls. This effect causes the measured permeability of a gas to be greater than the intrinsic permeability of the medium. He introduced an empirical constant for converting gas permeability to equivalent liquid permeability. He recommended to measure gas permeability at several pressures and to plot them against the reciprocal of the average pressure, the points would lie on a straight line. When the line is extrapolated the origin (infinite pressure), the intercept yields equivalent liquid permeability because all gases become liquids at infinite pressure. Alternatively, at high pressure, Klinkenberg effect becomes negligible, but as the flow rate increases, the deviation between pressure gradient and flow rate increases. Forchheimer (1901) demonstrated that the pressure gradient to sustain a high flow rate through a porous medium is higher than the one Darcy's equation would predict. As a result, he developed a quadratic form to relate the pressure gradient and fluid flow velocity. Forchheimer attributed the excess gradient required to inertial flow resistance. In fact, various physical meanings for this deviation have been discussed in the literature, but the generally accepted explanation is attributed to Wright (1968) and Geertsma (1974) who demonstrated that, at very high velocities, the deviation from Darcy's law arises due to inertial effects in pore contractions, expansions and bends followed by turbulent effects.

Cornell and Katz (1953) conducted experimental flow studies on different types of natural cores and found that at some critical flow rates, the deviation between pressure gradient and flow rate may appear. Janicek and Katz (1955) have correlated data obtained by Cornell and Katz with petrophysical data such as permeability and porosity of different formations. They concluded that the non-Darcy flow coefficient decreases with the increase of porosity and permeability. Several researchers proposed various empirical linear correlations under simple form for relating non-Darcy flow coefficient with permeability (Dake, 1978; Deghmoum et al., 2006; Eurgun, 1952; Geertsma, 1974; Jones, 1987; Tek et al., 1962).

Al-Rumhy and Kalam (1993) incorporated Klinkenberg constant in Forchheimer equation. They demonstrated that gas slippage correction is essential for determining non-Darcy flow coefficient from high rate gas flow data. Using experimental fluid flow on consolidated and unconsolidated sandstone, carbonate, and dolomite core samples, Liu et al. (1995), Thauvin and Mohanty (1998), Wang et al. (1999) obtained correlations of non-Darcy flow coefficient with respect to permeability, porosity,

and tortuosity. Blick and Civan (1988) integrated Reynolds number in their correlations. Tiss and Evans (1989) included the effect of confining pressures and they found that non-Darcy flow coefficient is inversely proportional to overburden stress.
Muskat (1946) showed that the pressure gradient in the transition region is proportional to the square of its argument, in particular the velocity, and it is independent of the viscosity of the fluid, while that for viscous flow is directly proportional to the viscosity. Tayler (1993) found that non-Darcy flow coefficient is independent of gas type. His experiments were based on the flow of argon, helium, and nitrogen through consolidated and unconsolidated cores.
The effect of mobile and immobile water saturation on non-Darcy flow coefficient has been well investigated (Al-Rumhy and Kalam, 1993; Evans. V and Evans. D, 1988; Evans et al., 1987; Frederick and Graves, 1994), As a result, they found that immobile water saturation is proportional to non-Darcy flow coefficient. Blom and Hagoort (1998) concluded that the effect of non-Darcy flow is much more pronounced in gas condensate than in dry gas. Wong (1970) found that an increase of 40 to 70% fluid saturation may multiply the value of non-Darcy flow coefficient by as much as eight. In addition, for multiphase flow, he stated that the non-Darcy flow coefficient can be correlated with effective permeability to gas at a given saturation. Evans. D and Civan (1994) demonstrated that the non-Darcy flow coefficient depends on rock and fluid properties, and it is crucial to be incorporated in relative permeability.
Firoozabadi and Katz (1979) performed nitrogen gas flow experiments on cores of different lengths. They found that non-Darcy flow coefficient is independent of porous media length. Temeng and Horne (1988) concluded that the lack of proportionality between pressure drop and flow rate doesn't imply a deviation from Darcy's law, in addition non-Darcy flow coefficient is length depend. This result is confirmed by Evans. D and Civan (1994) who demonstrated that non-Darcy flow coefficient determined by straight-line plots of Forchheimer's equation integrated over the core length must implicitly include the effect of the core length, although Firoozabadi, et al. (1992) disputed this point and proven it to be invalid. In fact, in the literature most of researchers recommended that intrinsic permeability and non-Darcy flow coefficient are independent of the fluid properties and depend only on the nature of the porous medium.
Noman and Archer (1987) explained the scatter observed in non-Darcy flow coefficient versus permeability plots depends on the heterogeneity of the porous medium, the internal surface roughness and the presence of clays. They noted that the presence of clays (type and amount) increases the roughness and thereby significantly increases the non-Darcy flow coefficient. Jones (1987) concluded that non-Darcy flow coefficient can be used as an indicator of reservoir heterogeneity in terms of permeability. Deghmoum et al. (2002) and Deghmoum and Hamaz (2006) established a general scale based on permeability- non-Darcy flow coefficient relationship for characterizing the heterogeneity of different reservoirs, their findings have been used as a good tool for reservoir characterization and to confirm if CO2 injectors are drilled in the correct positions for high injectivity performance.

2.1 NON-DARCY FLOW EQUATION

Forchheimer (1901) proposed the following quadratic equation of gas flow through porous media, which is in fact the correction of Darcy’s law (1856) in inertial dominated flow regime.

$$-\frac{dP}{dx} = \frac{\mu_g u}{k} + \beta \rho u^2 \quad (1)$$

Where dP/dx is pressure gradient, μ is dynamic fluid viscosity, k is the permeability of the medium, β is non-Darcy flow coefficient, ρ is fluid density and u is microscopic fluid velocity. According to Muskat (1946), many investigators have attempted to propose the general law of flow as:

$$-\frac{dP}{dx} = au + bu^n \quad (2)$$

and others have suggested the following relation:

$$-\frac{dP}{dx} = au^n \quad (3)$$

Where *n* is intermediate between 1 and 2. In equation 1, the right part links two terms; Darcy term which represents the viscous frictions that are proportional to filtration velocity due to the internal fluid friction force on the pore wall, and Forchheimer term which represents the inertial effects, proportional to square filtration velocity that are related to kinetic energy and the internal resistance.
In practice units, Equation 1 can be expressed as follow:

$$-\frac{dP}{dx} = \frac{\mu_g}{k}\left(\frac{Q}{A}\right) + 3.238 * 10^{-8}\beta\rho\left(\frac{Q}{A}\right)^2 \qquad (4)$$

The number 3.238×10^{-8} is the conversion factor and β is expressed in ft^{-1}. Cornell and Katz (1953) modified the form of the equation 1 by adding the equation of state, and integrating between upstream and downstream pressures.

$$(P_1^2 - P_2^2) = \left(\frac{2\bar{Z}RTL\beta}{A^2M}\right)q_m^2 + \left(\frac{2\bar{Z}RTL\mu_g}{kMA}\right)q_m \qquad (5)$$

Where M is the molecular weight, R is the constant of real gas and T is temperature. By multiplying both sides of equation 5 with $[(MA) / (2\bar{z}RT\mu_g Lq_m)]$, we get:

$$\frac{M(P_1^2-P_2^2)A}{2\bar{Z}RTL\mu_g q_m} = \beta\left(\frac{q_m}{A\mu_g}\right) + \frac{1}{k} \qquad (6)$$

Equation 6 has linear form $Y_{ck} = a\, X_{ck} + b$, where Y_{ck} is expressed in atm-sec/cm^2-cp and X_{ck} in gr/cm^2-sec-cp. The index "ck" is referred to transformation made by Cornell and Katz.
All parameters in equation 6 can be measured in lab. Thus, non-Darcy flow coefficient can be determined from the slope of Y_{ck} and X_{ck}, and the intercept of the straight line with Y_{ck} axis
can yield permeability of the medium *(b = 1/k)*.
The product of permeability and non-Darcy flow coefficient yields the following dimension length

$$\alpha=3.238*10^{-9} \qquad (7)$$

Where α is in μm, β in ft^{-1}, and *k* in md. It was suggested (Green and Duez, 1951) that the Reynolds number for a porous medium could be represented by the ratio ($NR_{pr} = \rho u\alpha/\mu$) of inertial to viscous forces. The characteristic length scale of the porous media in Reynolds number is therefore represented by the term α or β*K*. This definition has been used widely in the literature (Geertsma, 1974; Jones, 1978; Wright, 1968). This length in Reynolds number has been subjected to wide investigations to provide a correct Reynolds number to relate the corresponding flow regime. It was defined as the average grain diameter (Civan and Nguyen, 2005; Muskat, 1946), but physically it should represent the average pore than the grain diameter. Dybbs and Edwards (1984) defined it as the average pore size; Civan and Tiab (1989) called it the apparent pore size. It was considered as the square root of intrinsic permeability or permeability tensor (Magyari et al., 2005, Webb, 2006). Others regarded it as mean hydraulic radius (Hsu, 2005). Equation (1) can then be written as follow:

$$-\frac{dP}{dx} = \frac{\mu_g u}{k} + \left(1 + \frac{0.01\alpha\rho}{\mu_g}u\right) \qquad (8)$$

The right term in equation 8 may be recognized as a Reynolds number in porous media ($NRpr$). If NR_{pr} is too small, the flow is viscous dominated, the relationship between pressure gradient and filtration velocity is linear and Darcy's law is valid. As NR_{pr} increases, the pressure gradient begins to increase more than filtration velocity, thus Darcy's law admittedly loses its strict validity and the flow becomes moderately or entirely inertial.
Fanning friction factor is defined as: $f_{pr} = d\Delta P / (2L\rho u_2)$ (Cornel and Katz, 1953; Muskat, 1946; Tiab and Donaldson, 2004), where d is the same length defined in Reynolds number and L is the total length of the porous medium. Using Fanning friction factor versus Reynolds number, the different

flow regimes and the corresponding empirical equations can be expressed as follow (Cornel and Katz, 1953; Tiab and Donaldson, 2004):
If NR_{pr} is less than 0.08 as shown in figure 1, the flow regime is laminar and the relationship between the Reynolds number and the friction factor (f_{pr}) is:

$$f_{pr} = \frac{63.5}{NRe_{pr}} \tag{9}$$

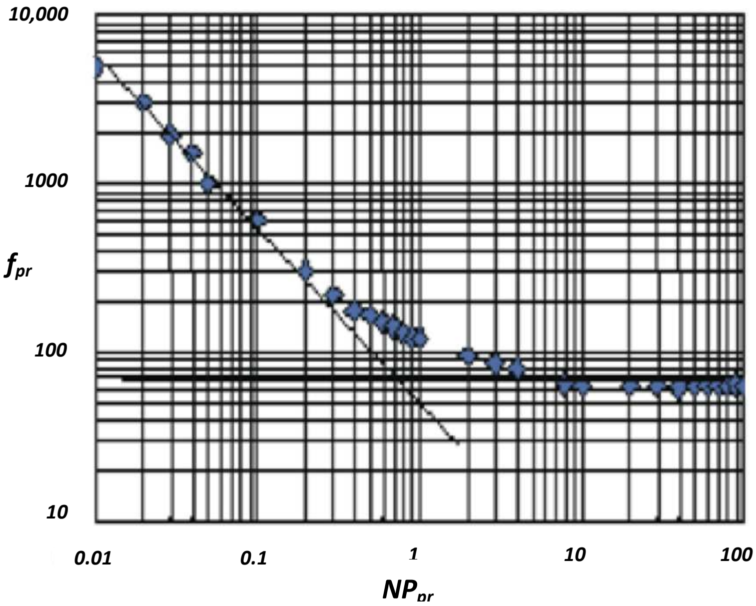

Fig.1: Friction factor VS Reynolds number in porous media (excerpt: Tiab and Donaldson, 2004)

The number 63.5 in equation 9 represents the slope of the straight line portion, as shown in figure 1. If NR_{pr} is between 0.08 and 8, the flow regime is inertial, and the friction factor can be written as

$$f_{pr} = e^{3.1423+1.7534NRe_{pr}^{-0.2805}} \tag{10}$$

and if NR_{pr} is greater than 8, the flow regime is turbulent which corresponds to the horizontal line of equation 11:

$$f_{pr} = 63.5 \tag{11}$$

According to Muskat (1946), the friction factor chart established by Fancher, Lewis, and Barnes, from different sandstone samples, consolidated and unconsolidated, shows that the transition region is not unique. It may start at NRpr equals to 2 for most samples, and it is around 8 for other samples. The interval of this inertial transition can be also extended to NRpr equal to 1000.
Laboratory flow test conducted on porous glass bead packs using laser Doppler anemometry (Dybbs and Edwards, 1984) demonstrated that Darcy flow regime is valid for NR_{pr} less than unity. At NR_{pr} equal unity, boundary layers were found to develop near the solid boundaries of the pore. If NR_{pr} is between 1 and 10 a transition region was found to occur and the flow changes from purely viscous to inertial dominated. In this region the boundary layers become more evident and an "inertial core" appears. This core flow outside the boundary layers is found to be the source of the nonlinearity between the pressure gradient and flow velocity.
This nonlinearity continues until NR_{pr} equals to 200. The flow in the range of NR_{pr} between 200 and 300 is unsteady state laminar which is characterized by laminar weak oscillations. It was observed that the formation of vortices occurs when NR_{pr} is between 300 and 350. Above 350 the flow is chaotic, similar to turbulent flow pattern.

It is important to remember that the transitional region may be quite different because of the nature and the complexity of the porous medium; consolidated, unconsolidated, type of cement between grains, the size and the structure of pore space as well as the degree of heterogeneity. In addition we expect from this appraisal that each porous medium type has its appropriate trend of flow regime and its specific physical properties. Since the intrinsic permeability is the characteristics of the porous medium and not of the fluid properties, the non-Darcy flow coefficient is solely related to porous medium properties. However, in multiphase flow, effective permeability and non-Darcy flow coefficient, for each phase, depend on the properties of the fluids and the porous medium (App and Mohanty, 2002; Evans. D and Civan, 1994).
This review is to give an opinion about how this domain is so interesting in the area of R&D. The discrepancies between efforts made by many investigators are a positive aspect because the convergence and the divergence between different visions and concepts lead to the development of new useful ideas.

3. STUDY OBJECTIVES

Non-Darcy flow coefficient obtained from fluid flow through porous medium is found by many researchers to be solely dependent on the internal architecture of the medium (Geertsma, 1974; Noman and Archer, 1987; Tayler, 1993), and it is recommended that this coefficient can be used as an indicator of permeability heterogeneity (Jones, 1987). Based on the above assessments, and to extend our initial work (Deghmoum and Hamaz, 2006; Deghmoum et al., 2002), which predicts zones and layers that present high inertial effect in the vicinity of production wells, the objectives of this study therefore are:

1. Integrating non-Darcy flow coefficient in reservoir characterization by developing correlations and scales, specifically for In Salah Gas fields, by which this coefficient can be evaluated on the base of petrohysical properties.
2. Integrating these scales in reservoir development in order to characterize reservoirs in terms of permeability, to predict zones of high and low inertial effects as well as to verify if CO_2 injector wells are drilled in the correct locations or to propose where new injectors can be drilled.

4. IN SALAH CCS PROJECT

This project is an integrated part of gas production development plan. CO_2 comes from the gas production of three fields; Teg, Reg and Krechba with 4 to 10% of CO_2 concentration. The specification of gas commercialization is 0.3% of CO_2. In order to cut CO_2 emission in the atmosphere, a gas processing plant is constructed in Krechba field where CO_2 capture is made by chemical process using amines, CO_2 drying and compression are made at 185bars, and CO_2 transport is completed via 8-in diameter pipelines (Ringrose et al., 2009; Wright et al., 2009).
The CO_2 injection in the carboniferous aquifer of 1900m depth, is at a rate of one million ton per annum (1MMTPA) using three horizontal wells, Fig.2. This industrial demonstration project is started in 2004. The total quantity of CO_2 to be sequestered is 17MMT. The height of this geological formation is 20m. Its porosity is 16% and its permeability is 10md. This project is the world's first full-scale CCS project at a gas field.
The goals of the project are: 1). Demonstrate to stakeholders that geological CO_2 sequestration at industrial scale constitutes a viable and an effective solution for GHG mitigation option through analyses and studies conducted on Krechba field. 2). Provide assurance that secure geological storage of CO_2 can be cost-effectively verified and that long-term assurance can be provided by short-term monitoring, and, 3). Set precedents for the regulation and verification of CO_2 geological storage (Wright et al., 2009).
In Salah region is composed by wide and simple anticline structures and constituted by Carboniferous and Devonian sandstone reservoirs. The three fields Teg, Reg and Krechba, located in the north, are developed during the initial phase. Based on production decline forecast from above fields, a pipeline network was extended to the south where the following five fields: Hassi Moumene, Gour Mahmoud, InSalah, Garet el Bafinet, and Bouteraa will be developed to assure a stable production plateau of 9.10^9scum per year.

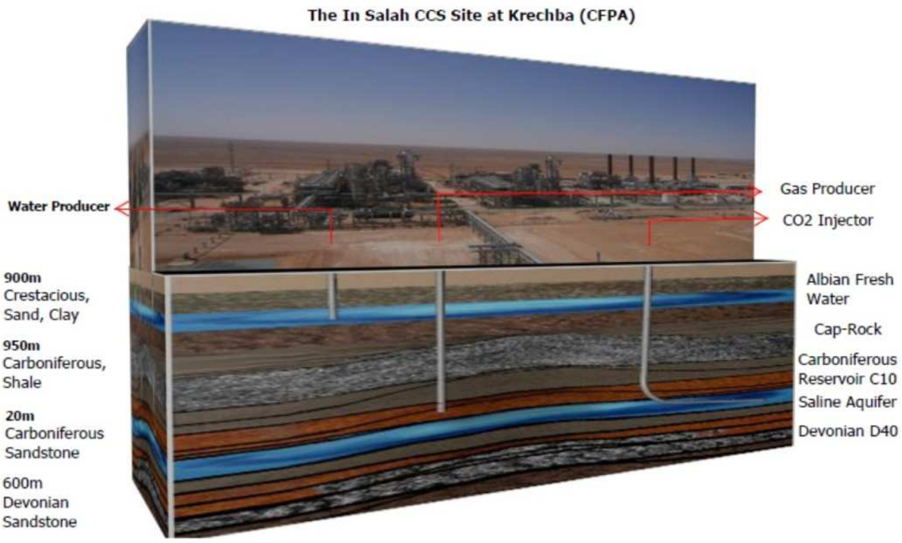

Fig.2. Krechba CCS project, In Salah, Algeria (excerpt: Deghmoum and Baddari, 2012)

For the development of new aspects related to fluid flow through porous medium under non-Darcy flow regime. The following reservoirs are selected: 1). the Carboniferous reservoir of Krechba field and, 2). the Devonian reservoir of other fields such as: Hassi Moumene, Gour Mahmoud, Teg, In Salah, Garet el Bafinet, and Bouteraa, as shown in Fig.3.

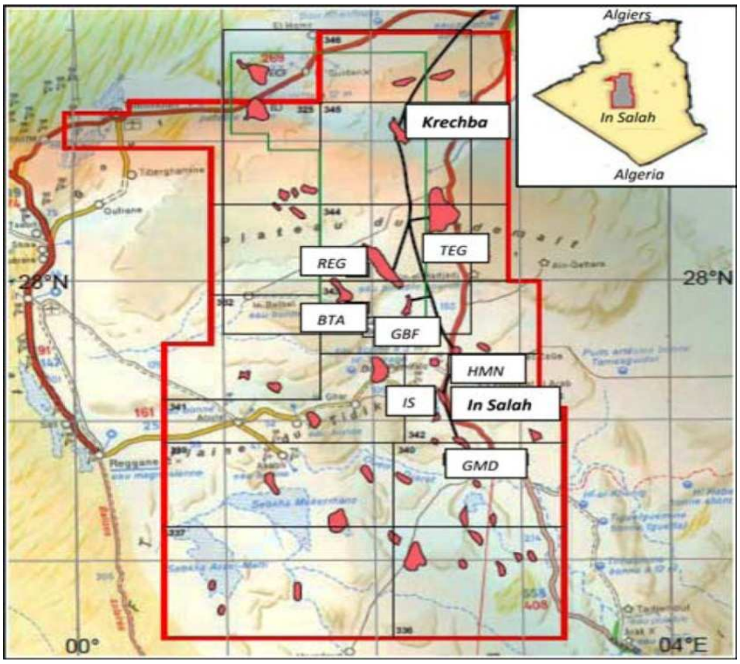

Fig.3. In Salah fields' location

The laboratory gas flow test under pressure blow down or unsteady-state conditions is performed on 84 core samples, selected from cited reservoirs. In addition, artificial and homogeneous porous media represented by metallic plugs that are used for calibrating porosimeter and permeameter are used to provide a base-line of non-Darcy flow characteristics and to help the interpretation of non-Darcy flow through natural cores .

Non-Darcy flow coefficient versus permeability relationship is developed for each reservoir. General scale of these properties is established for improving reservoir characterization in terms of permeability heterogeneity. The first application in this study is conducted on Krechba Carboniferous reservoir, and it is extended to the Devonian reservoirs of other fields. The findings show that this developed scale, can be considered as a good tool for reservoir characterization and, confirm if CO_2 injectors are drilled in the correct position in term of injectiviy performance.

5. LABORATORY SETUP

The base line of non-Darcy flow characteristics is a primordial reference for limiting the range of non-Darcy flow coefficient values and interpreting flow test in natural porous media. This base line is established on 6 metallic porous media of different physical properties (permeability and porosity). For natural porous media, 84 consolidated sandstone core samples of 1in-diameter (2.54cm) obtained from In Salah gas reservoirs, have been cleaned by extraction in soxhlets with appropriate chemical formulation MAT (methanol/Acetone/Toluene: 15/15/70 in volume) for extracting organic material, and with methanol for eliminating salts, afterwards, the core samples are dried under 65°C until the stabilization of their dry weight.

The non-Darcy flow test is conducted by helium under unsteady state conditions using Core Measurement System, which is an automated apparatus. The confining pressure is applied at 800 psi as referential stress and permeability, porosity, non-Darcy flow coefficient are measured for each sample.

6. RESULTS AND INTERPRETATION

The experimental result shows that non-Darcy flow coefficient is inversely proportional to permeability. The physical meaning of this phenomenon can be related directly to the internal architecture of the medium in term of pore size, pore configuration and distribution. Large pores decrease the pressure loss and minimize inertial effect.

All developed equations from log-log plot have linear form: Y = aX+b, (Fig. 4 to Fig. 11). These equations for each medium are as follow:

1. Artificial Porous Media (Fig.4):

$$\beta = 10^{-1.7491\log(k)+\log(11.1746)} \tag{12}$$

2. Krechba (KB) Carboniferous Reservoir (Fig.5):

$$\beta = 10^{-1.7276\log(k)+\log(11.2823)} \tag{13}$$

3. Teguentour (TEG) Devonian Reservoir (Fig.6):

$$\beta = 10^{-2.6423\log(k)+\log(10.9288)} \tag{14}$$

4. In Salah (IS) Devonian Reservoir (Fig.7):

$$\beta = 10^{-1.4662\log(k)+\log(11.0283)} \tag{15}$$

5. Garet El Bafinet (GBF) Devonian Reservoir (Fig.8):

$$\beta = 10^{-1.5592\log(k)+\log(11.0385)} \tag{16}$$

6. Gour Mahmoud (GMD) Devonian Reservoir (Fig.9)

$$\beta = 10^{-1.4586\log(k)+\log(10.8166)} \tag{17}$$

7. Hassi Moumene (HMN) Devonian Reservoir (Fig.10)

$$\beta = 10^{-1.4879\log(k)+\log(11.3419)} \tag{18}$$

8. Bouteraa (BTA) Devonian Reservoir (Fig.11)

$$\beta = 10^{-2.4123\log(k)+\log(10.6270)} \quad (19)$$

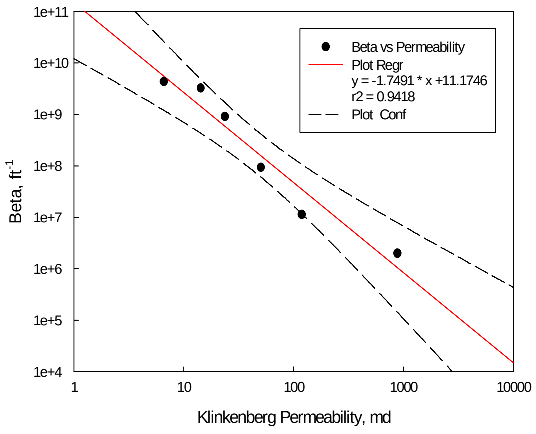

Fig.4. k vs. β, metallic porous samples

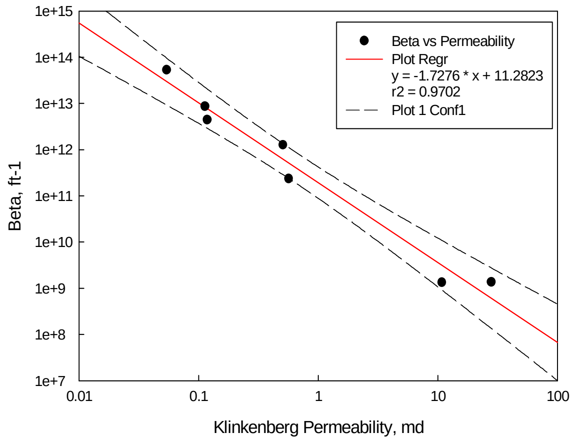

Fig.5. k vs. β, (KB) field, Carboniferous

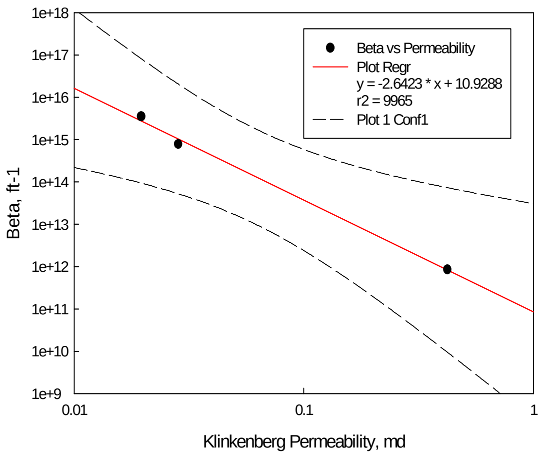

Fig.6. k vs. β, (TEG) field, Devonian

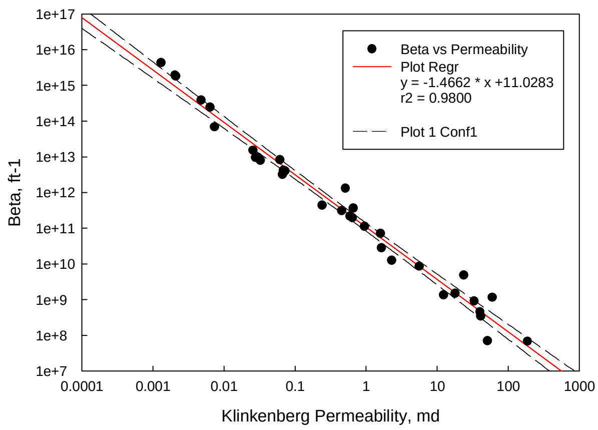

Fig.7. k vs. β, (IS) field, Devonian

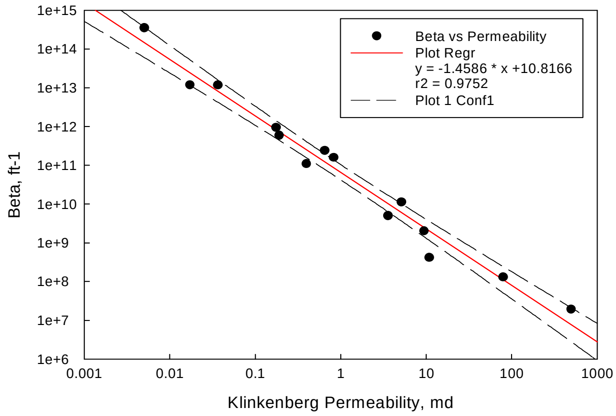

Fig.8. k vs. β, (GBF) field, Devonian

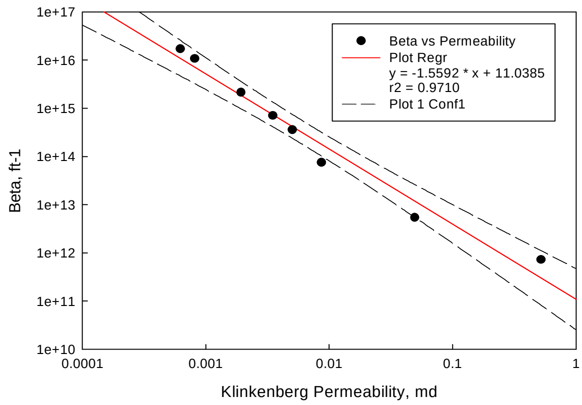

Fig.9. k vs. β, (GMD) field, Devonian

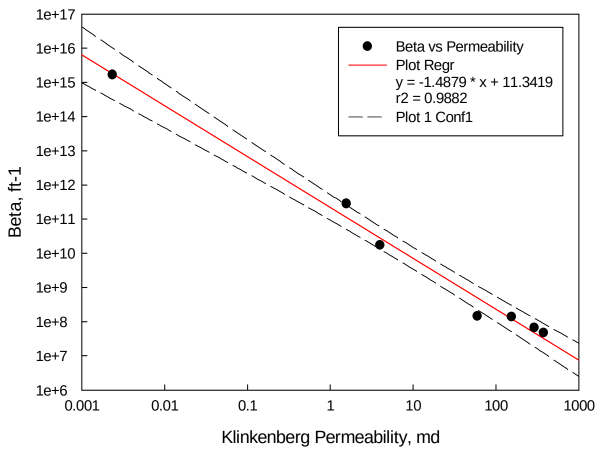

Fig.10. k vs. β, (HMN) field, Devonian

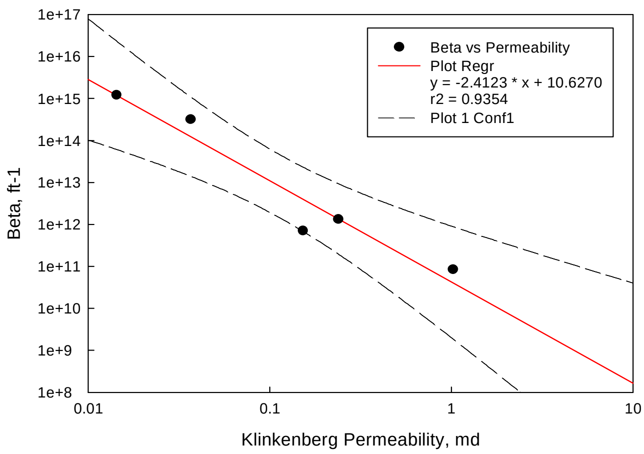

Fig.11. k vs. β, (BTA) field, Devonian

The limits for each medium in terms of permeability and non-Darcy flow coefficient are summarized in the table 1.

Tab.1: Non-Darcy flow coefficient and Permeability limits of all Porous media

Porous Media	β Min		β Max	
	β, ft^{-1}	K, md	β, ft^{-1}	K, md
Metallic	2.00E+06	881	4.31 E+09	6.59
KB	2.32E+09	12.88	1.23E+11	1.29
TEG	8.29E+11	0.4220	2.76E+15	0.0196
IS	5.02E+07	186.025	1.80E+15	16.40
GBF	3.02E+11	0.52	1.09E+16	0.00062
GMD	7.71E+06	494.34	1.47E+14	0.0053
HMN	3.26E+07	374.63	1.81E+15	0.0023
BTA	4.04E+10	1.02	1.19E+15	0.0143

From developed correlations and transformations as well as boundary limits, a scale that relates non-Darcy flow coefficient and permeability is illustrated in figure 12. This figure shows different zones: highly homogeneous, homogeneous, slightly homogenous, heterogeneous and strongly heterogeneous in term of permeability and inertial effect.

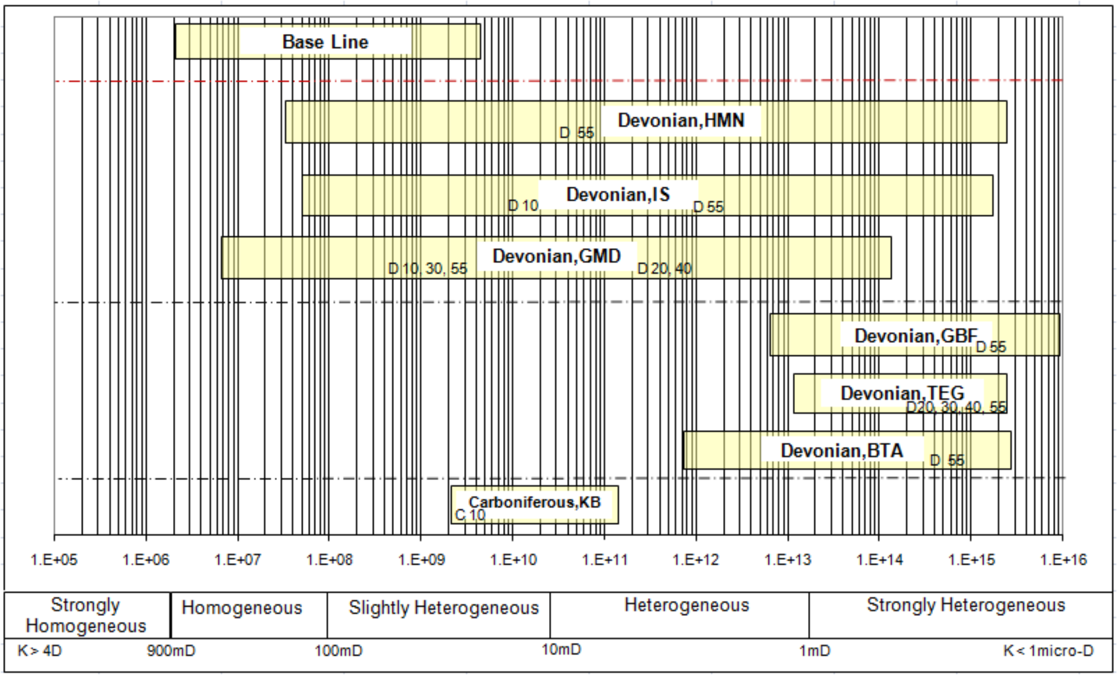

Fig.12. In Salah reservoir characterization scale

Artificial porous media are positioned in the range of very low inertial effect, and characterized by highly homogeneous aspect. The Carboniferous reservoir of Krechba is classified as slightly heterogeneous with an aspect of homogeneous affinity. Concerning the Devonian reservoir of other fields, two categories can be distinguished:

The first is characterized by high non-Darcy flow coefficient and high heterogeneity. So that we can consider the tight Devonian reservoir of the following fields Teguentour, Boutraa and Garet El Befinat, belongs to this category.

The second is characterized by the large interval of non-Darcy flow coefficient. The classification of this category varies from homogeneous (compared to base line set up by metallic samples) to highly heterogeneous. As the Devonian reservoir in all In Salah fields is not homogeneous in term of permeability, the developed scale is found to be coherent with this physical aspect, principally in characterizing multilayer reservoirs. Thus, this scale can reflect the heterogeneous characteristics of all analyzed porous media, and it may serve as a modeling tool to confirm certain reservoir geological models.

The iso-non-Darcy flow coefficient mapping, which is considered as a new concept, can be used in reservoir development for selecting adequate zones to drill new wells or to confirm if the wells are well positioned in zones of low inertial effect. For accrediting this approach, it is important to evaluate permeability and non-Darcy flow coefficient from core samples in order to establish the relationship between these two physical parameters. To take into account the upscaling feature due to large contrast between core and field dimensions, the iso-non-Darcy flow coefficient mapping should be developed on the basis of Well Test permeability for each well and the corresponding non-Darcy flow coefficient accomplished from previous empirical equations.

In this study, the application of this concept is illustrated on the Carboniferous reservoir of Krechba field depending on the availability of data. Except one well Test analysis data obtained from CO_2 horizontal injector well (KB 503Z), the rest of field data are a combination of core and log analyses

gathered from 15 wells. The average permeability for each well is computed and the corresponding non-Darcy flow coefficient is obtained from the developed scale.
The iso-permeability map has been established on Krechba field. Figure 13, shows that the apex of Carboniferous structure is characterized by good permeability comparatively to the Eastern and the Western flanks as well as to the Southern and the Northern parts of the field. Figure 14 is the developed iso-non-Darcy flow mapping which indicates the existence of two zones of high inertial effects. The first one is around the well KB14 and the second one is around the well KB1. These zones are not recommended to drill producer or injector wells. Thus, it can be predicted via this study that the following producer wells: KB1, KB5, KB8, KB13, KB14 have poor performance because they are drilled in zones of high heterogeneity effect. Effectively, the productivity index (IP) of KB1 as an example, is 2373m^3/d/bar. It is zero for KB5, and it is equal to 6203m^3/d/bar for KB8. Whereas for the wells that are out of these zones, the IP is considerable. It is around 12000m^3/d/bar for KB2 and 13000m^3/d/bar for KB6z.
Contrary to CO_2 horizontal injectors, KBz 503 and KBz 501 that are in zones of low heterogeneity, Fig. 14, The CO_2 horizontal injector KBz 502 is located in zone of high heterogeneity and it needs normally more energy for high injectivity performance. This consequence is possibly the cause of CO2 leakage detected in KB5 located in the vicinity of KBz 502 due to induced fractures created by high injection pressure.
This technique may provide substantial benefit solution to avoid the wrong well location and additional well stimulation jobs and consequently considerable performance and cost effective to CO_2 geological sequestration technology.

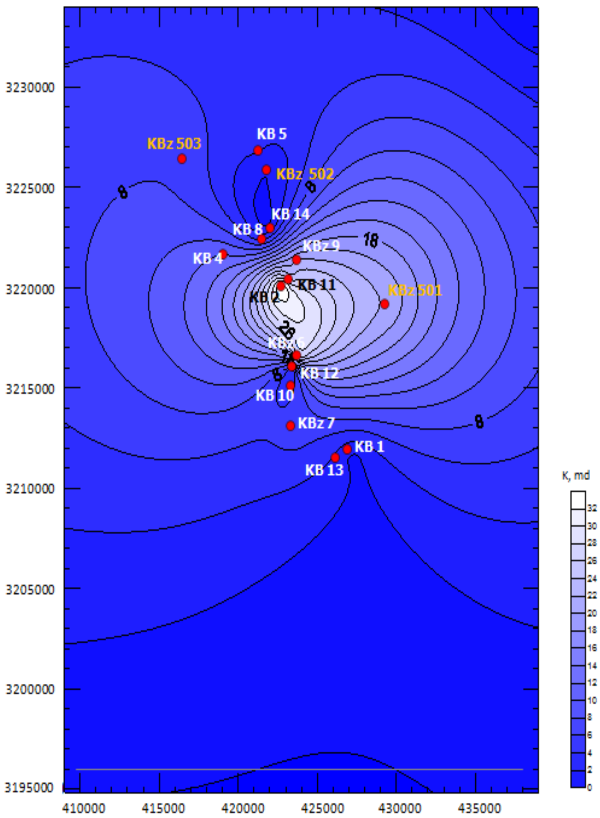

Fig.13. k Distribution, Krechba field, Carboniferous reservoir

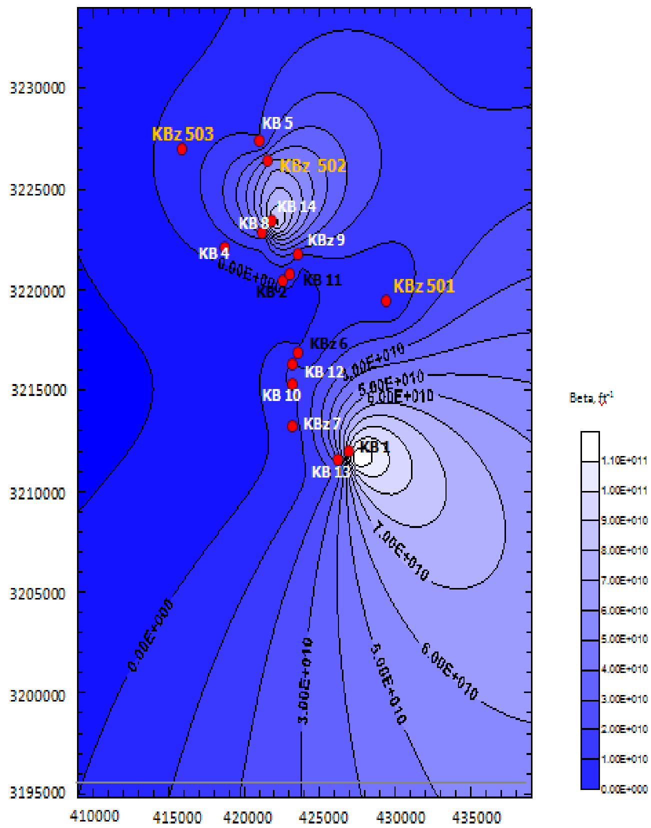

Fig.14. β Distribution, Krechba field, Carboniferous reservoir

It is important to notice that these findings are preliminary and depend on the quality of the available data principally permeability values deduced from logs. For a good practice, these values should be computed from well Testing Analysis to get representative iso-non-Dacy flow coefficient distribution at large scale.

7. CONCLUSION

The architecture of the skeleton of the medium is the main parameter that controls permeability as well as the inertial effects, and the developed scale permits the characterization of reservoirs and layers in terms of homogeneity of permeability.

The non-Darcy flow mapping improves the selection of zones for drilling new wells. The special case study in Krechba field is targeted to verify the position of CO_2 injectors. This method can also be used as a good tool for reservoir management and reservoir development.

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NOMENCLATURE

dp/dx	:	Pressure gradient
f_{pr}	:	Fanning friction factor
IP	:	Productivity Index
K	:	Permeability of the porous medium
Q	:	Flow rate
MMT	:	Million of ton = 10^6ton
MMTPA	:	Million of ton per annum
MMV	:	Measuring, monitoring and verification program
NR_{pr}	:	Reynolds number in porous media
u	:	Filtration velocity
α	:	Characteristic length scale in Reynolds number
β	:	Non-Darcy flow coefficient
ΔP	:	Pressure difference
ρ	:	Fluid density
μ	:	Dynamic fluid viscosity

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