Journal of Petroleum & Environmental Biotechnology

Sharma et al., J Pet Environ Biotechnol 2017, 8:5
DOI: 10.4172/2157-7463.1000336

Research Article Open Access

A Treatise on Non-Darcy Flow Correlations in Porous Media

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Abstract

Non-Darcy Flow behavior is important for describing fluid flow in consolidated or unconsolidated porous media when abrupt changes in velocity dominates. A criterion or a generalized equation is required to understand this flow behavior in the isotropic/anisotropic carbonate and sandstone reservoirs, and naturally or hydraulically fractured reservoirs. Various correlations and equations have been reviewed in this paper to quantify this non-Darcy coefficient (i.e., beta coefficient) mathematically. It has been observed that this coefficient is highly dependent on rock properties (mainly porosity, permeability and tortuosity). An algorithm to determine the values of the beta coefficient by using the correlations have been presented and coded and converted in to a robust user-friendly simulator. This simulator can take a large amount of data set as *input* and will generate a large data set of beta values as *output*. The obtained or calculated beta value is very useful for predicting the change in pressure gradient with respect to velocity and hence can give the best estimate of hydrocarbon production under challenging or adverse pressure drop conditions.

Keywords: Non-Darcy flow; Viscous flow; Beta coefficient; Simulator; Rock properties

Introduction

The relationship between the pressure drop and flow rate in problems of fluid flow through porous media is known to be affected by the nature of flow through the porous matrix. It has been observed by Darcy that the pressure drop remains proportional to the rate of flow at low Reynolds Number [1]. But at high flow rate, flow will exhibit non – linearity with respect to velocity which make Darcy's Law inapplicable at these conditions. To account this non-linear relationship in between pressure gradient and velocity, to turbulence, a non-Darcy term was introduced. When the fluid particles enter in to the porous (consolidated and unconsolidated formations), they are subjected to acceleration and deceleration process depending on the flow rate conditions. In the laminar flow, there is a continuous reversible interchange of kinetic and pressure energy as the acceleration and deceleration process continues. But, in turbulent conditions or high flow rate conditions, the interchange includes significant irreversibility due to the extra fluid motion above that occurring in laminar flow [2]. This extra fluid motion is caused by the inertial effects in the deceleration process. The phenomenon is referred as Non-Darcy flow and was first introduced and investigated by Forcheimer [3]. Different terminology and names have been proposed by various investigators for the Forchheimer's Non-Darcy coefficient. It has been named as Turbulent Factor, Characteristic Constant of Porous Medium, and Coefficient of inertial resistance, Velocity coefficient, Coefficient of Inertial Resistance, non-Darcy coefficient and the Beta Factor. Table 1 represents the different nomenclature of Non-Darcy term and its applicability in porous media.

Numerous attempts haven been made by Cornell and Katz, Janicek and Katz, Geertsma, Firoozabadi and Katz, Pascal and Kingston, Norman Jones, Ruth and Ma, Liu, Ganesh, Coles and Hartman, Thauvin and Mohanty, Reid, Saskia and Jacques, Cooper, Fourar and Lenormand, Li, Yu Shu Wu, Olson Barree, Friedel and Voigt, Khaniaminjan and Goudarzi, Macini, Xiaoyan, Yang to understand this non-Darcy flow coefficient in different types of formations particularly natural porous medium, fractured reservoirs, consolidated and unconsolidated formations [4-10]. It has been carefully observed from their studies that this non-Darcy coefficient/beta factor can be related with the rock properties like porosity, permeability, tortuosity, and specific surface area, grain and pore size.

The present paper has three fold objectives:

- Thorough Literature Review of the existing Non- Darcy Correlations for Porous Media. (All the theoretical and empirical correlations for quantifying non-Darcy coefficient i.e., Beta Factor (β) have been carefully reviewed, presented and discussed in detail.)
- To prepare an algorithm for the determination of beta factor by using selected correlations taking permeability, porosity and tortuosity as input parameters.
- To convert and code the algorithm in to a robust simulator which can compute the beta values for a given set of data. To check the robustness of this simulator, it is validated and verified by a test/synthetic data obtained from the available open-source.

This study presents an understanding of non-Darcy flow behavior in porous formations (natural or fractured) and discuss all the non-Darcy flow correlations available in the literature. An algorithm and a user-friendly simulator has been presented to determine the beta values for a large input data set [11-20].

Darcy and Non-Darcy Flow Correlations

In most of the formations, the flow pattern is governed by Darcy's law which describes the linear relationship between pressure gradient and velocity. Darcy's law is inapplicable or inadequate in the case if the flow rate is significantly high which is usually near the well bore conditions. This Law is adequate to describe the flow of fluid and pressure drop at low Reynolds number *($Re < 1$)*. A uni- directional

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Received May 29, 2017; **Accepted** August 05, 2017; **Published** August 12, 2017

Citation: Sharma V, Sircar A, Mohammad N, Patel S (2017) A Treatise on Non-Darcy Flow Correlations in Porous Media. J Pet Environ Biotechnol 7: 336. doi: 10.4172/2157-7463.1000336

SN	Correlations as proposed by Researchers	Year	Nomenclature of Non-Darcy Coefficient (β)	Media / Formation	Reference
1	Darcy	1856	Linear relationship between pressure gradient and velocity	Darcy Flow in porous media	[1]
2	Forchheimmer	1901	'α' is introduced to express non- Darcy effect for porous media	First introduced the non- Darcy term beyond the Darcy region	[3]
3	Cornell and Katz	1953	β is Turbulent Factor	Consolidated porous media (sandstone, limestones and dolomites)	[4]
4	Janicek and Katz	1955	β is Characteristic Constant of Porous Medium	Porous Media	[5]
5	Katz	1959	β is Turbulent Factor	Porous Media	[25]
6	Geertsma	1974	β is Coefficient Resistance of Inertial	Sandstone formations	[6]
7	Firoozabadi and Katz	1979	β is Velocity coefficient	Carbonates and Sandstones	[7]
8	Pascal and Kingston	1980	β is non-Darcy coefficient	Low permeability hydraulically fractures gas wells	[8]
9	Norman, Shrimanker and Archer	1985	β is Coefficient Resistance of Inertial	High – Rate Gas Wells	[9]
10	Jones	1987	β is Inertial Coefficient	Heterogeneous reservoir rocks	[10]
11	Ruth and Ma	1990	β is Forchheimer Coefficient	Porous Media	[11]
12	Liu, Civan and Evans	1995	β is non-Darcy coefficient	Consolidated and Unconsolidated Porous Media	[12]
13	Ganesh, Muku Sharma and Gary Pope	1998	β is non-Darcy coefficient	Heterogeneous Formation (Study on carbonate gas condensate reservoir)	[26]
14	Coles and Hartman	1998	β is Inertial Coefficient	Dry and Saturated Core Samples	[13]
15	Thauvin and Mohanty	1998	β is non-Darcy coefficient	Porous Media	[14]
16	Reid and Hwang	1998	βeffective is coefficient effective non-Darcy	Porous Gas-Water System (Sandstone samples)	[27]
17	Saskia and Jacques	1998	β is Inertial Coefficient	Gas Condensate Reservoirs	[14]
18	Cooper, Xiuli and K K Mohanty	1999	β is non-Darcy coefficient	Anisotropic sandstone and carbonate reservoirs	[15]
19	Fourar and Lenormand	2000	β is Inertial Factor	Two phase flow through Fractured Reservoirs	[16]
20	Li	2001	β is non-Darcy flow coefficient	Sandstone Reservoir	[17]
21	Yu Shu Wu	2002	β is non-Darcy flow coefficient	Porous and Fractured Reservoir	[18]
22	Olson	2004	β is non-Darcy flow coefficient	Hydraulically multi fractured horizontal well	[19]
23	Barree, Lopez and Lynne	2005	β is inertial flow parameter	Hydraulically fractured wells	[20]
24	Friedel and Voigt	2006	β is non-Darcy flow coefficient	Tight Gas Reservoirs	[21]
25	Khaniaminjan and Goudarzi	2008	β is non-Darcy flow coefficient	Unconsolidated Porous Media	[22]
26	Macini, Mesini and Viola	2011	β is non-Darcy flow coefficient	natural and artificial unconsolidated porous media	[23]
27	Xiaoyan	2016	β is non-Darcy flow factor	Sandstone reservoir	[24]
28	Yang, Yang	2016	β is inertial coefficient	Fractured-vuggy medium.	[24]

Table 1: Nomenclature of non-Darcy term and its applicability.

steady state flow rate equation for an incompressible laminar flow through a horizontal porous medium as proposed by Darcy is given as Eq. 1 [21-24].

$$-\frac{\partial P}{\partial x}=\frac{\mu}{k}V \tag{1}$$

Where, P is pressure (Pa), V is seepage velocity (Darcy velocity, m/s), μ is dynamic viscosity (Pa s), k is Darcy permeability, m^2.

The rapid change in the pressure gradient as a function of velocity and high molecular interactions in the porous media makes Darcy's Law insignificant at high flow rate condition. In the non-Darcy flow, the inertial forces and kinetic energy changes significantly due to the expansion and contraction of gas in the porous medium. Under this effect, flow will exhibit non –linearity with respect to velocity. To account this non-linearity between pressure gradient and velocity, to turbulence, a non-Darcy term was first introduced by Forcheimer [3] which was later validated and modified by Katz [25].

An extension to Darcy law as proposed by Firoozabadi and Katz [7], describes the flow behavior beyond linear flow/Darcy region. The pressure drop due to this phenomenon can be expressed as Eq. 2.

$$-\frac{dP}{dL}=\mu\frac{v}{k}+\alpha v^2 \tag{2}$$

Where, 'α' is constant for a given porous media, lb mass/ft,

v is the fluid velocity, ft/sec and k is permeability, md.

Eq. 2 was modified by Katz [25] and the constant 'α' (for a given porous media) was expressed as the product of fluid density 'ρ' and turbulent factor 'β'. This turbulent factor accounts the onset of non-Darcy flow. The non-linearity between pressure drop and seepage velocity under the turbulence and high flow rate conditions is expressed as Eq. 3.

$$-\frac{dP}{dL}=\frac{\mu}{k}v+\beta p v^2 \tag{3}$$

Katz [25] with the investigations of Forcheimer [3] introduced a new term i.e., turbulence factor 'β' which was further investigated and examined by various researchers for different formations particularly natural porous medium, fractured reservoirs, consolidated and unconsolidated formations.

Cornell and Katz [4] correlated and predicted the flow of gases through the interstices of consolidated porous media (sandstone, limestones and dolomites) at rates leading to the deviation from viscous flow to turbulent flow region. He conducted electrical resistivity measurements on 24 sandstone, limestone and dolomite samples and proposed a correlation for predicting turbulence factor in the consolidated medium. Cornell introduced the term *Turbulence Factor,* 'β Cornell' (coefficient of turbulence term of flow equation) which is dependent on electrical resistivity factor (F), fractional porosity (X), effective diameter of pore structure (DE) and dimensionless geometric constant in turbulence term of flow equation *(k2)*. This factor is expressed as Eq. 4:

$$\beta cornell = \frac{(32)(F^{3/2})}{(K_2)(D_E)(X^{1/2})} \quad (4)$$

After making 'F = 4/ϕ' approximation on Cornell and Katz Turbulence Factor Equation, Janicek and Katz [5] proposed the following equation (Eq. 5) for determining the *Characteristic Constant of Porous Medium* - 'β Janicek'

$$\beta_{janicek} = \frac{5.5\times10^9}{k_{md}{}^{5/4}\phi^{3/4}} \quad (5)$$

Where, 'β Janicek' is in 1/ft, k is permeability in md and ϕ is porosity in fraction.

Geertsma [6] expressed beta factor as coefficient of inertial resistance and presented following empirical relationship (Eq. 6) between beta factor, porosity and permeability for sandstone formations. The suggested correlation is valid for formations 100% saturated with liquid or gas.

$$\beta_{geertsma} = \frac{4.7877*10^{-11}}{\phi^{5.5} * k^{0.5}} \quad (6)$$

Where, 'β *Geertsma*' is in 1/ft, k is permeability in md and ϕ is porosity in fraction.

Firoozabadi and Katz [7] through their several experimentations and investigations introduced a new terminology to the β factor which is 'velocity coefficient' as it denotes the changes in flow regimes. The term β was represented as turbulence factor (defined as extra fluid motion consuming extra energy) by many researchers but the expressions were unacceptable as the concept overlooked the stages of progress of the growth of shear and tension components in laminar mode. Firoozabadi selected several sets of data for correlating the velocity coefficient with permeability or porosity and proposed the following expressions (Eq. 7 to Eq. 11). The data were on dry cores with gas – flow measurements excluding the effects of Klinkenberg slip interference.

$\log \beta_{firoo} = m \log k + b$

(m = 1.201; b = 23.83; Carbonates) (7)

$\log \beta_{firoo} = m \log (k^{0.5} \phi^{1.5}) + b$

(m = 1.695; b = 17.89; Carbonates) (8)

$\log \beta_{firoo} = m \log (k^{0.1} \phi) + b$

(m = 0.991; b = 19.92, Carbonates) (9)

$\log \beta_{firoo} = m \log (k\phi) + b$

(m = -1.074; b = 21.42, Carbonates) (10)

$\log \beta_{firoo} = m \log \phi + b$

(m = -5.149; b = 9.70, Carbonates) (11)

where, m and b are correlating constants.

Pascal and Kingston [8] presented a new method for predicting both the non-Darcy flow coefficient and vertical fractures length based upon single-point, variable flow drawdown tests of shallow, low permeability gas reservoir. They proposed following empirical correlation (Eq. 12) in between non-Darcy flow coefficient and permeability:

$$\beta pascal = \frac{1.463*10^{12}}{k^{1.176}} (1/\text{ft}) \quad (12)$$

where, β pascal is non-Darcy coefficient 1/ft, k is permeability in md.

In the early studies, it was supposed that fluid flowing at high velocity through porous media would suffer excessive energy loss from turbulence. The coefficient β was therefore termed as turbulence factor. Noman [9] explained that the energy losses occurs due to the i) convective acceleration and deceleration of fluid particles as they travel through pore throats and ii) tortuous path in a porous media and termed β as coefficient of inertial resistance. Data from over hundred gas wells were analyzed to obtain the following correlation (Eq. 13) for coefficient of inertial resistance.

$$\log \beta_{norman} = m \log (k/\phi.S_g)^{-0.5} + c \quad (13)$$

where, m = 2.4388, c = -2.4071, βnorman is in 1/ft, k is in md and Sg is gas saturation.

Jones [10] suggested that the inertial coefficient β is strongly influenced by the degree of permeability heterogeneity in a reservoir rock and proposed the following expression (Eq. 14) to incorporate its effect.

$$\beta liu = \frac{8.91*10^8 * \tau}{k*\phi} (1/\text{ft}) \quad (14)$$

Ruth and Ma [11] correlated the beta factor with permeability and Forchheimer Number (Fo). The importance of using Fo is that it makes the correlation (Eq. 15) valid for predicting non-Darcy flow at macroscopic scale.

$$\beta\ ruth\ and\ ma = \mu\ Fo/ko\ \rho u \quad (15)$$

where, β *ruth and ma is Forchheimer coefficient (1/m),* μ = viscosity (Pa.s), Fo = Forchheimer Number, ko = permeability at zero velocity (m^2), ρ = density (kg/m^3)

Liu [12] proposed a general correlation for the non- Darcy flow coefficient with respect to permeability, porosity and tortuosity using a wide variety of data from consolidated and unconsolidated porous formations. This correlation (Eq.16) implicitly includes the effect of overburden stress through permeability, porosity, tortuosity and the effect of existence of other fluid phases through the effective permeability.

$$\beta liu = \frac{8.91*10^8 * \tau}{k*\phi} (1/\text{ft}) \quad (16)$$

Ganesh [26] proposed an empirical correlation (Eq.17) to obtain effective beta value for a heterogeneous gas condensate reservoir which is given as below:

$$\beta_{ganesh} = 0.07/k\ a_v\ (1-\phi) \quad (17)$$

where, β_{ganesh} = 1/ft, k = md and av is specific surface area.

Coles and Hartman [13] derived the following relationship (Eq. 18) which allows the inertial coefficient to be estimated as a function of effective permeability and effective porosity by performing measurements on dry and saturated core samples. He observed that, at higher flow rates, the non- Darcy effect penetrates further in to the formation and decreases rapidly as the distance from the wellbore increases. This high non-Darcy effect near the well bore increases the pressure drop required to establish a desired gas well production rate, thus decreases the productivity.

$$\beta coles = \frac{1.07*10^{12}\phi^{0.449}}{k^{1.88}}(1/\text{ft}) \tag{18}$$

Thauvin and Mohanty [14] observed that the non-Darcy is proportional to the square of the superficial velocity at the macroscopic scale. The coefficient will depend on the morphological characteristics of the medium i.e., permeability, tortuosity and porosity. As the mean throat radius increases, the non - Darcy coefficient decreases sharply, the permeability increases, the porosity increases slightly and tortuosity decreases slightly. The proposed expression is as follows (19):

$$\beta thau = \frac{5180.2016*\tau^{3.35}}{k^{0.98}*\phi^{0.29}}(1/\text{ft}) \tag{19}$$

The correlation (Eq. 20) for beta calculations in porous formations as proposed by Ergun and Orning, 1949 is as follows:

$$\beta ergun = \frac{0.3682*10^{-7}}{\phi^{1.5}*k^{0.5}}(1/\text{ft}) \tag{20}$$

where, k is in md.

Reid and Hwang, Sakia and Jacques [27,28] performed the non-Darcy measurements in Porous-Gas-Condensate reservoirs and supported the investigations supported by earlier researchers on gas reservoirs. Cooper [15] in their investigations explained the non- Darcy flow effects in Anisotropic Porous Media. Non-Darcy flow coefficients, permeabilities and electrical tortuosity are measured in carbonate and sandstone core samples with layers both parallel and perpendicular directions to flow and in nonlayered, anisotropic cores. They proposed following correlation (Eq. 21):

$$\beta cooper = \frac{4.059*10^{-21}*\tau^{1.943}}{k^{1.023}}(1/\text{ft}) \tag{21}$$

Fourar and Lenormand [16] reviewed three different approaches to account inertial effects in two-phase flow through fractures: inertial factor, passability and Lockhart Models. The inertial factor is expressed in Eq. 22 and Eq. 23:

$$\beta_L = 572 \times -0.51 \tag{22}$$

$$\beta_G = 159 \times 1.49 \tag{23}$$

where, βL is inertial factor (liquid), βG is inertial factor (Gas) and X is determined by the least square method as a power law.

Li [17] presented the following generalized correlation (Eq. 24) to simulate the high-velocity gas flow problems in sandstone reservoirs:

$$\beta \text{li} = \frac{350.52}{\phi*k}(1/\text{ft}) \tag{24}$$

Yu Shu Wu [18] investigated the single phase and multiphase non-Darcy flow in porous and fractured reservoirs and presented the following relation (Eq. 25) for non-Darcy flow coefficient of fluid:

$$\beta_f(S_W, k_{rf}) = \frac{C_\beta}{(kk_{rf})^{5/4}\left[\phi\left(S_f - S_{fr}\right)\right]^{3/4}} \tag{25}$$

k_{rf} - Relative permeability to phase f.

S_{fr} - Relative saturation to phase f.

C_β- Non-Darcy flow constant.

Olson [19] tested three different types of proppants with three different types of resins in conductivity cell under field conditions to study the effect of multiphase non-Darcy pressure effects in hydraulically fractured horizontal well. They proposed the following correlation (Eq. 26) to represent the non-Darcy flow behavior at this scale.

$$\beta_p = \frac{a}{\left(K.K_{rp}\right)^{n1}\left(\phi S_p\right)^{n2}} \tag{26}$$

Where, k is abosulte permeability in mD and β is in 1/ft, n_1, n_2 and 'a' are empirical constants, krp is relative permeability to the fluid phase being considered and Sp is phase saturation.

However, Barree [20] proposed following empirical correlation (Eq. 27) for studying the effect of non Darcy flow in hydraulically fractured reservoirs:

$$N_{re} = \frac{\beta k_d \rho v}{\mu} \tag{27}$$

Where, NRe is Reynolds number, ρ is density of gas, v is the velocity of gas, μ is viscosity, β is inertial flow parameter, atm-sec^2/g Friedel and Voigt [21] performed simulation in black oil simulator to investigate the non –Darcy flow in tight gas reservoirs with fractured wells and proposed following correlation (Eq. 28):

$$\beta_f = 1.10^{11} k_f^{-1.11} \tag{28}$$

Where, βf = non-Darcy flow coefficient (1/m), kf is in md

Khaniaminjan [22] studied the non-Darcy flow effect in unconsolidated porous media made of sand (quartz) packing of different sizes and presented the three-different correlation (Eq. 29 to Eq. 31) given as –

$$\beta(\phi,k) = \frac{9\times10^9}{k^{-6/7}\phi^{-8/7}} \tag{29}$$

$$\beta(\phi,k) = \frac{4.8\times10^{11}}{k^{-1.8}\phi^{-0.48}} \tag{30}$$

$$\beta(k) = \frac{17.2\times10^{10}}{k^{1.76}} \tag{31}$$

Where, K is in mD and β is in 1/ft.

Macini [23] performed laboratory measurements in natural and artificial unconsolidated porous media and also observed the effect of non – Darcy Flow. Xiaoyan investigated some sandstone samples and observed following relations (Eq. 32 to Eq. 34) to exists –

An approximately logarithm relation between permeability and non-Darcy flow factor

$$\beta Xiaoyan = \frac{3.3792*10^{15} + 9.8*10^{13}*1n(\text{k})}{1} \tag{32}$$

An approximately exponential relation between the acceleration coefficient and permeability

$$\text{Ca} = 1\times10^{10}\ \text{e-}7\times10\text{\^{}}15\text{k} \tag{33}$$

An approximately linear relation between the non-Darcy flow factor and acceleration factor

$$\text{Ca} = -0.0001\beta + 1\times10^8 \tag{34}$$

Where Ca is acceleration coefficient, β is non-Darcy flow factor and k is permeability Yang used artificial vuggy medium to study the effect of non-Darcy two – phase flow [24]. They rewrote forchheimer equation and proposed an equation (Eq. 35) that allows the prediction of inertial coefficient, β for fractured vuggy medium.

$$\beta_{yang} = \frac{0.005e^{0.0322\frac{d}{w}}}{K^{0.5}\left(\phi_f^{5.5} + \phi_v^{7}\right)} \quad (35)$$

Where, β is in cm^{-1} and K is in μm^2

ϕ_f = fracture porosity

ϕ_v = vug porosity

d = vug diameter and

w = fracture width

Algorithm Formulation and Description

An algorithm has been prepared by using selected 12 correlations. Rock properties mainly - permeability, porosity and tortuosity will act as key input parameters for the computation of beta factor coefficient. A step wise description of the algorithm is given as below and represented in Figures 1 and 2.

Step 1: Start the Programme

Step 2: Obtain the petrophysical parameters of the porous media such as permeability (k), porosity (ϕ) and tortuosity (τ).

Step 3: Find all the relevant beta correlations.

Step 4: If permeability (k), porosity (ϕ) and tortuosity (τ) all the properties are known then Liu, Thau and Cooper Correlation will be selected for the calculation of Beta factor. Else, move to STEP 6.

Step 5: The obtained values of Beta factor are given as follows:

1. β_{liu} = ...(1/ft)
2. β_{Thau} = ...(1/ft)
3. β_{Cooper} = ...(1/ft)

Step 6: If permeability (k) and porosity (ϕ) are known then Cales and Hartman, Janicek and Katz, Macdonlad, Ergun, Geertsma and Li Correlations will be selected for the calculation of Beta Factor. Else, move to STEP 7.

Step 7: The obtained values of Beta factor are as follows:

1. β_{cales} = ...(1/ft)
2. $\beta_{janicek}$ = ...(1/ft)
3. β_{mac} = ...(1/ft)
4. β_{ergun} = ...(1/ft)
5. $\beta_{geertsma}$ = ...(1/ft)
6. β_{liu} = ...(1/ft)

Step 8: If only permeability (k) is known, then *Pascal,* Jonnes and Xiaoyan Correlation will be selected for the calculation of Beta Factor. Else move to Step 11.

Step 9: The obtained values of Beta factor are as follows:

1. β_{Pascal} = ...(1/ft)
2. β_{Jones} = ...(1/ft)
3. $\beta_{Xiaoyan}$ = ...(1/ft)

Step 10: All the computed values of Beta factor after following steps 5, 7 and 9 are given as follows:

1. β_{liu} = ...(1/ft)
2. β_{Thau} = ...(1/ft)
3. β_{Cooper} = ...(1/ft)
4. β_{cales} = ...(1/ft)
5. $\beta_{janicek}$ = ...(1/ft)
6. β_{mac} = ...(1/ft)
7. β_{ergun} = ...(1/ft)
8. $\beta_{geertsma}$ = ...(1/ft)
9. β_{liu} = ...(1/ft)
10. β_{Pascal} = ...(1/ft)
11. β_{Jones} = ...(1/ft)
12. $\beta_{Xiaoyan}$ = ...(1/ft)

Step 11: End the programme.

Validation and Testing of Data with the Proposed Simulator

The data has been selected from the literature available in the public domain as open source material. The properties - permeability, porosity and tortuosity (Table 2) has been taken as input parameters to check the efficacy of the created simulator. Table 3 is the additional test data which has been collected by Amao by performing laboratory experimentations on Core Samples – C1, C3, C6, C9 and C10 [29]. Four correlations namely Pascal, Coles, Janicek and Macdonald have been selected for validation and simulation. The beta values calculated by Amao by using these correlations are having different units and dimensions. We have converted all the beta values in to 1/ft units to make the consistency in the unit. The beta value data set has been presented and tabulated in Table 4. A reservoir simulator has been prepared by using Net Beans in Java Script which will be validated by the test data of C1 sample as given in Table 4.

The simulator is using 12 active correlations for the computation of beta values. These correlations are:

1. Liu Correlation.
2. Thauvin Correlation.
3. Copper Correlation.
4. Coles Correlation.
5. Janicek Correlation.
6. Macdonald Correlation.
7. Ergun Correlation.
8. Geertsma Correlation.
9. Li Correlation.
10. Pascal Correlation.
11. Jones Correlation.
12. Xiaoyan Correlation.

The petrophysical values of core sample C1 will be taken from Table

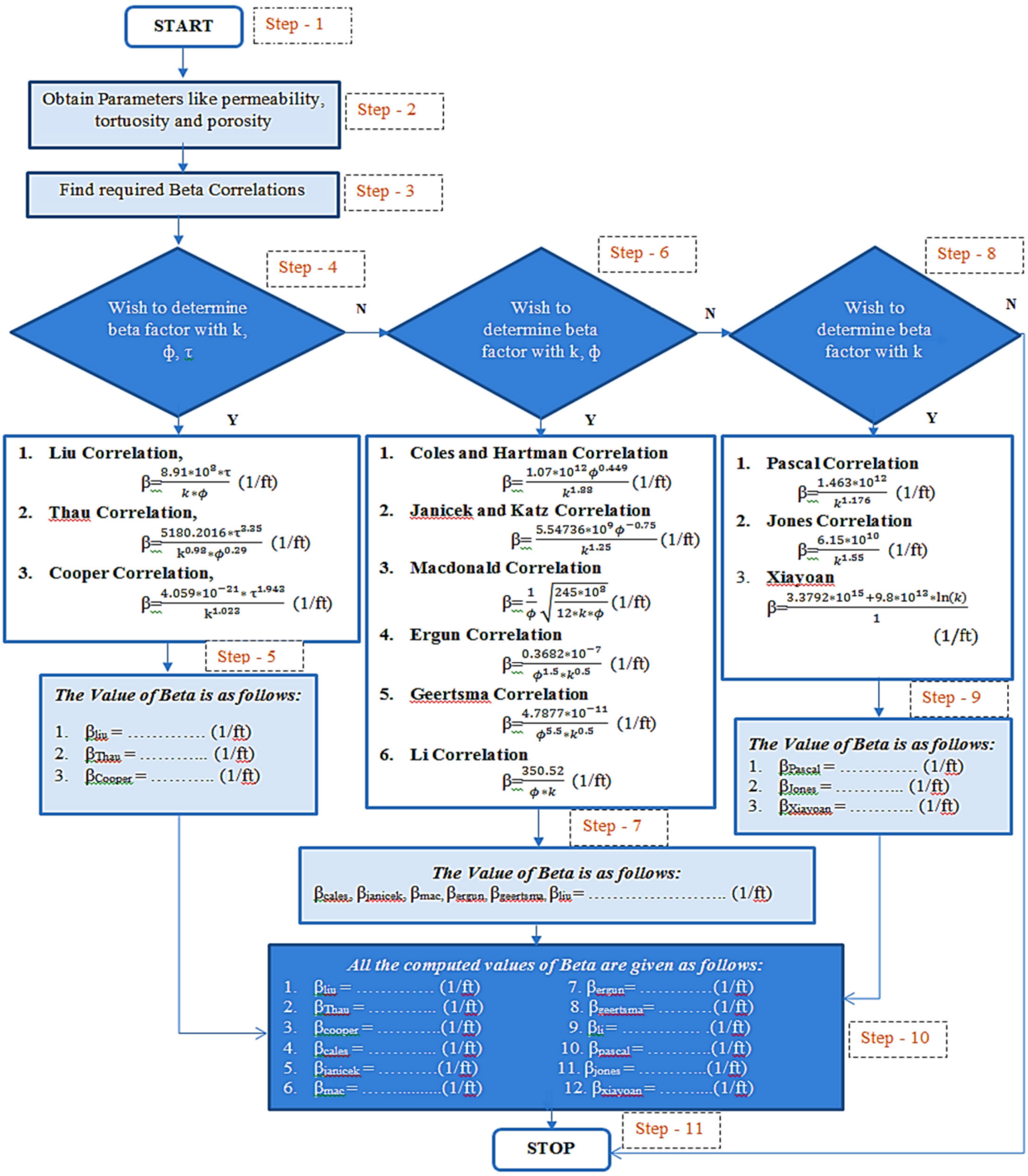


Figure 1: Algorithm for computing non-Darcy co-efficient.

2 to compute the beta values from the simulator. A sample example has been presented in Figure 3 where this simulator will compute beta values for C1 Sample. The steps are as follows:

Step 1: Welcome to the Non-Darcy Flow Coefficient Determination Application. Click Start for running the application (Figure 3a)

Step 2: Obtain the petrophysical parameters of the porous media such as permeability (k), porosity (ф) and tortuosity (τ). (Figure 3b) Input: k = 5.0486 md, ф = 0.18 and τ = 1.25

Step 3: Choice of Correlation (Figure 3c) _ Select option 1 if you want to calculate beta by using k, ф and τ. _ Select option 2 if you want to calculate beta by using k and ф. _ Select option 3 if you want to calculate beta by using k. _ Click Next

Step 4: Selection of Correlation (k, ф and τ) (Figure 3d) Option 01 is chosen for running the Programme.

Step 5: Output Window for selected choice. *The Values of Beta are as follows:*

1. β_{liu} = 24.123 (1/ft)
2. β_{Thau} = 3663.07 (1/ft)
3. β_{Cooper} = 1.195 (1/ft)

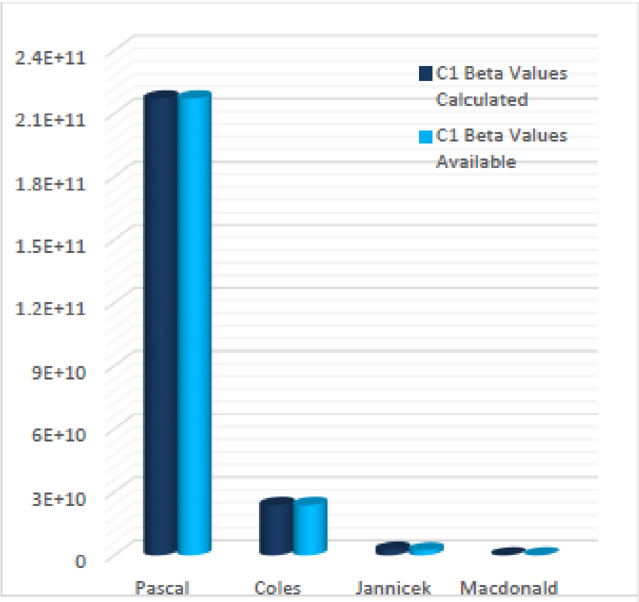


Figure 2a: Plot: Correlations vs. calculated and available beta values for core sample C1.

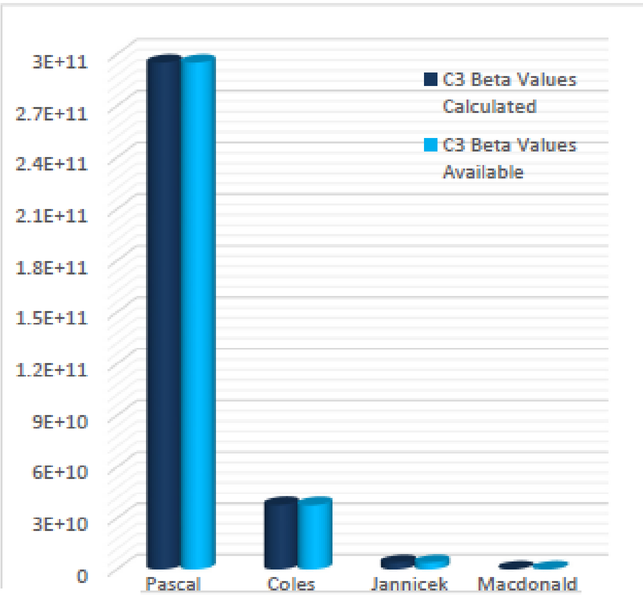


Figure 2b: Plot: Correlations vs. calculated and available beta values for core sample C3.

Select Yes if you wish to calculate the beta values by using other correlations (options) (Figure 3e).

Step 6: Selection of other set of correlations (k and ϕ). Option 02 is chosen for running the Programme (Figure 3f). Click Next.

Step 7: Output window for selected choice (Figure 3g)

The values of Beta is as follows:

1. β_{cales} = 23700000000 (1/ft)

2. $\beta_{janicek}$ = 2621000000 (1/ft)

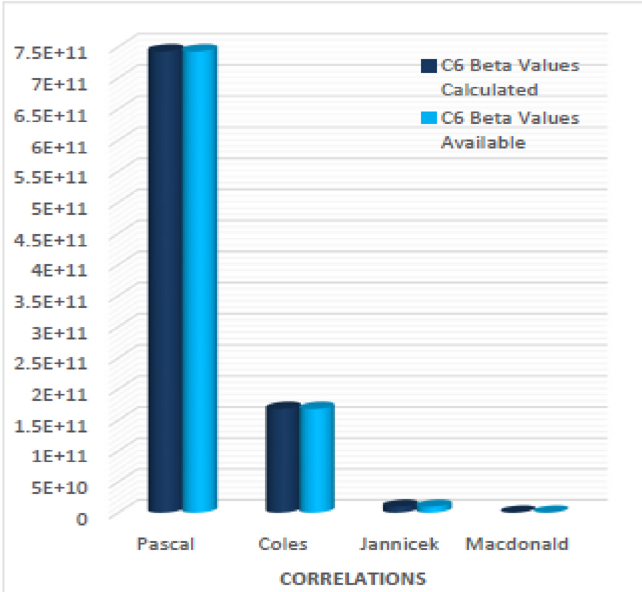


Figure 2c: Plot: Correlations vs. calculated and available beta values for core sample C6.

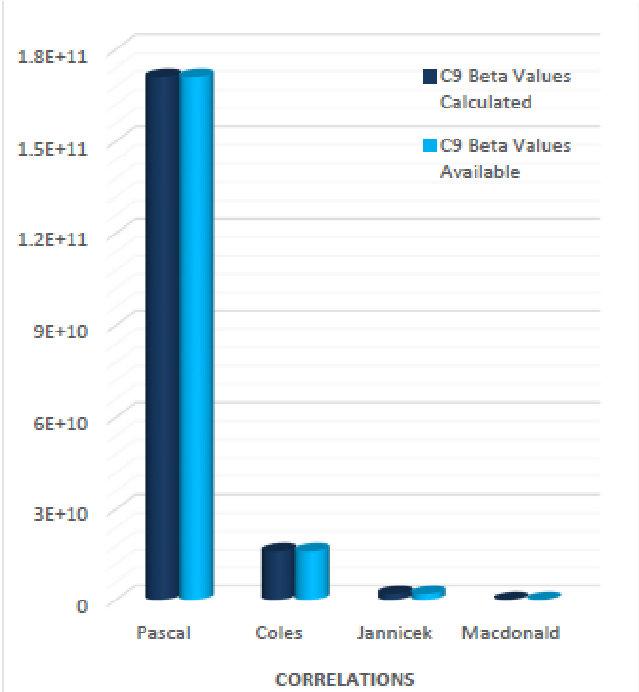


Figure 2d: Plot: Correlations vs. Calculated and available and beta values for core sample C9.

3. β_{mac} = 257090 (1/ft)

4. β_{ergun} = 2.094×10^4 (1/ft)

5. $\beta_{geertsma}$ = 2.434×10^7 (1/ft)

6. β_{liu} = 379.601 (1/ft)

Select Yes if you wish to calculate the beta values by using other

Citation: Sharma V, Sircar A, Mohammad N, Patel S (2017) A Treatise on Non-Darcy Flow Correlations in Porous Media. J Pet Environ Biotechnol 7: 336. doi: 10.4172/2157-7463.1000336

correlations (options)

Step 8: Selection of other set of correlations (k only) (Figure 3h) Option 03 is chosen for running the Programme. Click Next.

Step 9: Output window for selected choice (Figure 3i)

1. $\beta_{Pascal} = 2.17 \times 10^{11}$ (1/ft)

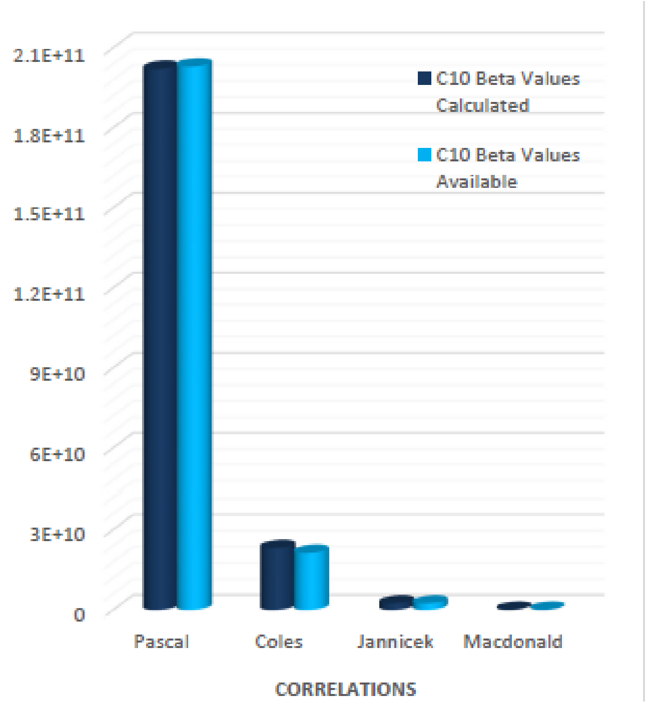


Figure 2e: Plot: Correlations vs. calculated and available beta values for core sample C10.

Cores	Porosity (Fraction)	Permeability (md)
C1	0.1829	5.0486
C3	0.173	3.8944
C6	0.1812	1.7786
C9	0.1838	6.182
C10	0.185	5.3625

Table 2: Porosity and permeability data for 5 different core samples [1].

Correlations	Beta Values Obtained from Literature (in different units); Available Values				
	C1	C3	C6	C9	C10
Pascal (1/m)	7.15E + 11	9.70E + 11	2.44E + 12	5.63E + 11	6.66E + 11
Coles (1/cm)	7.80E + 08	1.24E + 09	5.52E + 09	5.34E + 08	7.00E + 08
Janicek (1/cm)	8.60E + 07	1.24E + 08	3.19E + 08	6.65E + 07	7.91E + 07
Macdonald (1/ft)	257090	322130	439254	230626.7	245127.33

Table 3: Beta values calculated by Amao, 2007 through experimentation.

2. $\beta_{Jones} = 4.99 \times 10^{9}$ (1/ft)

3. $\beta_{Xiaoyan} = 3.53 \times 10^{15}$ (1/ft)

Step 10: Final result (Figure 3j)

1. $\beta_{liu} = 24.123$ (1/ft)

2. $\beta_{Thau} = 3663.07$ (1/ft)

3. $\beta_{Cooper} = 1.195$ (1/ft)

4. $\beta_{cales} = 23700000000$ (1/ft)

5. $\beta_{janicek} = 2621000000$ (1/ft)

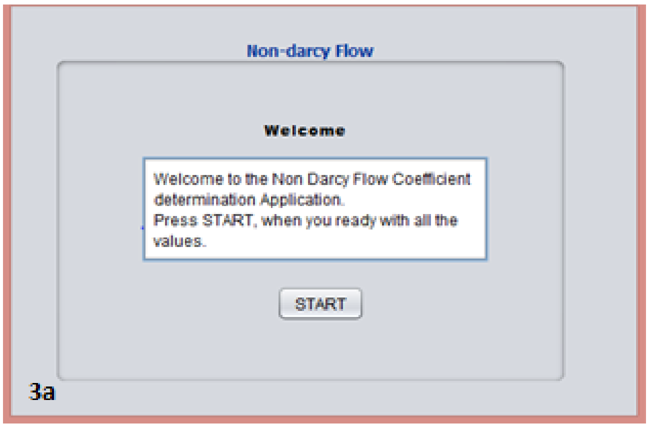
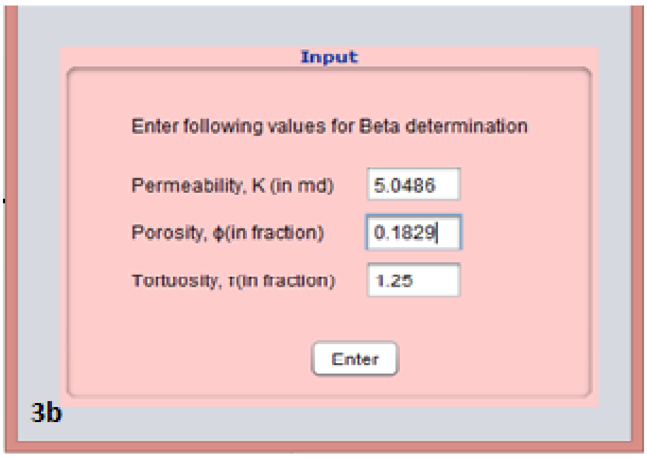


Figure 3: Validation of simulator with the test data (Test data is obtained from Amao [1]).
3a: Welcome to the non-Darcy flow coefficient determination application. Click Start for running the application.

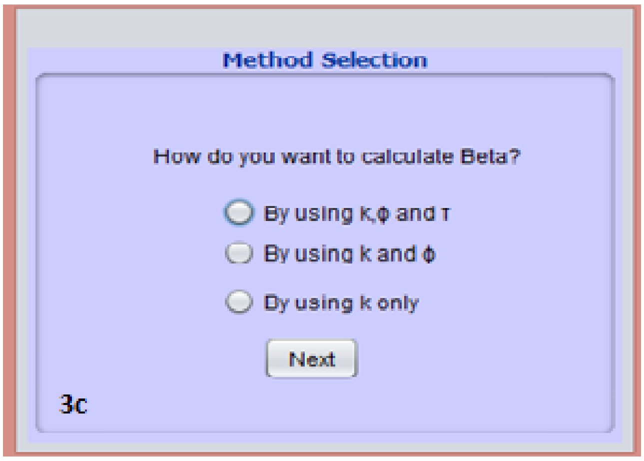


3b: Obtain the petrophysical parameters of the porous media such as permeability (k), porosity (ɸ) and tortuosity (τ). Input: k = 5.0486 md, ɸ = 0.18 and τ = 1.25

Correlations	Beta Values Obtained from Literature (in 1/ft units)				
	C1	C3	C6	C9	C10
Pascal	2.17E + 11	2.95E + 11	7.43E + 11	1.71E + 11	2.03E + 11
Coles	23700000000	37700000000	1.68E + 11	16200000000	21300000000
Janicek	2320000000	3780000000	9720000000	2020000000	2400000000
Macdonald	257090	318202	439254	230626	245217

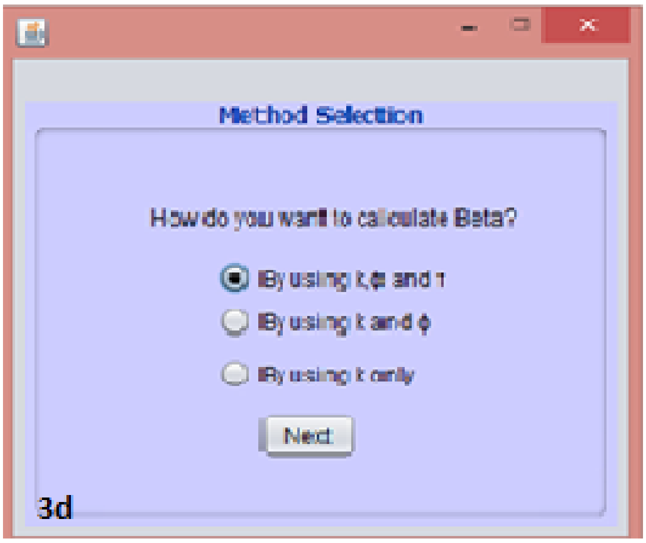
Table 4: Available values (Beta values obtained from literature converted in 1/ft units).

Citation: Sharma V, Sircar A, Mohammad N, Patel S (2017) A Treatise on Non-Darcy Flow Correlations in Porous Media. J Pet Environ Biotechnol 7: 336. doi: 10.4172/2157-7463.1000336



3c: Choice of correlation.

- Select option 1 if you want to calculate beta by using k, φ and τ.
- Select option 2 if you want to calculate beta by using k and φ.
- Select option 3 if you want to calculate beta by using k.
- Click Next

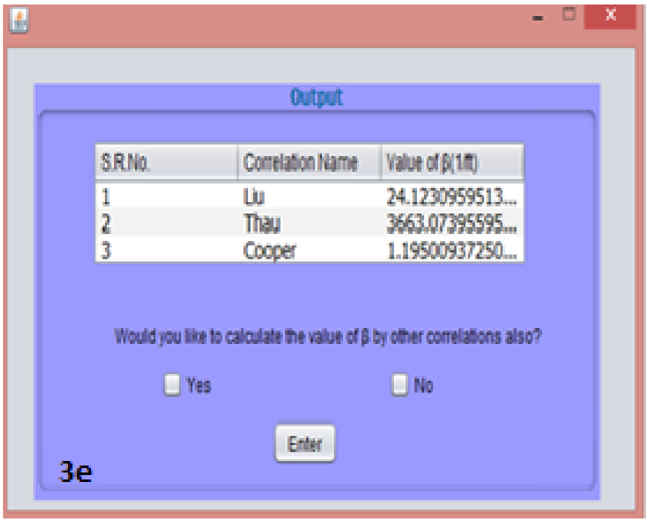


3d: Selection of correlation (k, φ and τ) option 01 is chosen for running the programme.

6. β_{mac} = 257090 (1/ft)
7. $\beta_{ergun} = 2.094 \times 10^4$ (1/ft)
8. $\beta_{geertsma} = 2.434 \times 10^7$ (1/ft)
9. β_{liu} = 379.601 (1/ft)
10. $\beta_{Pascal} = 2.17 \times 10^{11}$ (1/ft)
11. $\beta_{Jones} = 4.99 \times 10^9$ (1/ft)
12. $\beta_{Xiaoyan} = 3.53 \times 10^{15}$ (1/ft)

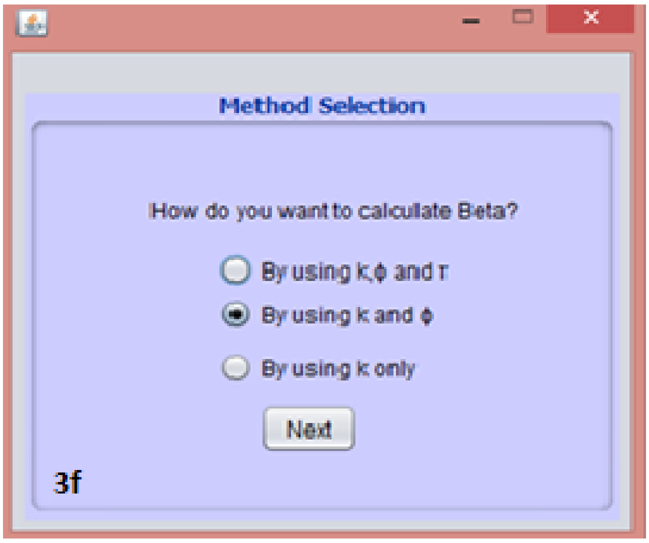
Validation of core sample data with simulator

- **Available values:** Table 4 gives the available values of the beta factor computed by Amao by using correlations – Pascal, Jones, Janicek and Macdonald.



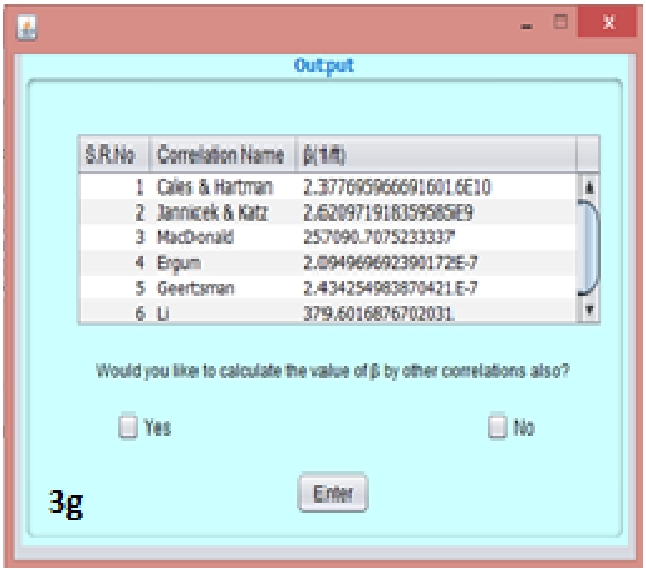
3e: Output window for selected choice.
The value of beta is as follows:
1. β_{Liu} = 24.123 (1/ft)
2. β_{Thau} = 3663.07 (1/ft)
3. β_{Cooper} = 1.195 (1/ft)

Select Yes if you wish to calculate the beta values by using other correlations (options).



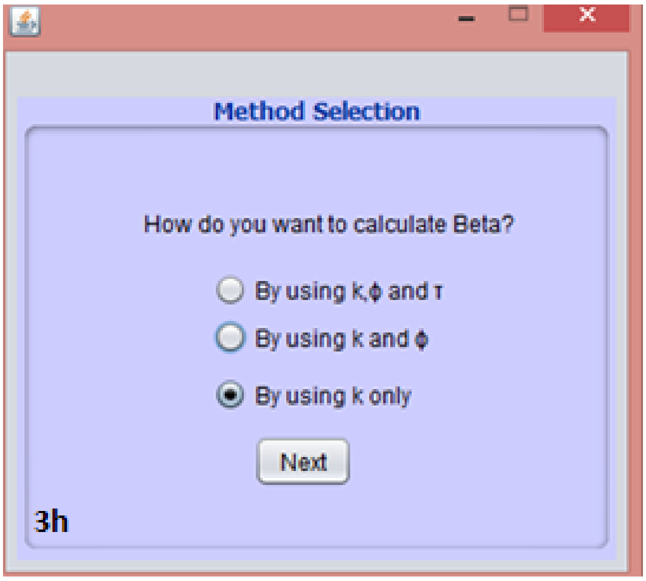
3f: Selection of other set of correlations (k and φ). Option 02 is chosen for running the Programme, Click Next.

- **Computed/calculated values:** The beta values computed by the simulator for C1 core sample has been tabulated in Table 5. Only the beta values for Pascal, Coles, Janicek and MacDonald correlations has been presented [30-34].
- The computed values are compared with the available values obtained from the literature and no significant difference is observed which makes our simulator a robust one. Figures 2a-2e represents the histogram plotted in between available and computed values and it indicates negligible % level of difference.
- The proposed simulator is validated by the available data and can be used to calculate beta factor for any type of porous

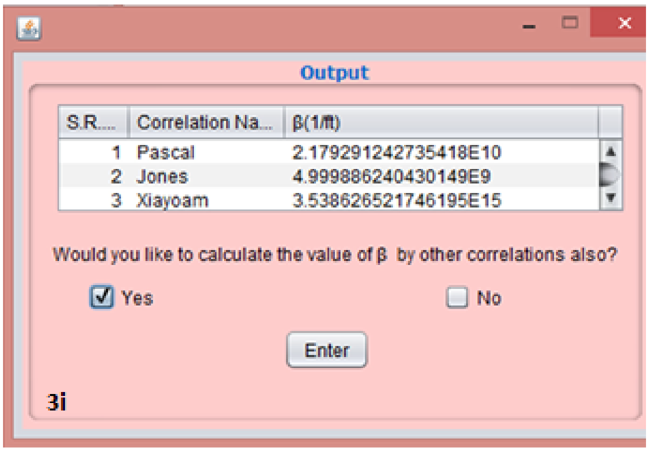


3g: Output window for selected choice.
The values of beta are as follows:
1. β_{cales} = 23700000000 (1/ft)
2. $\beta_{jannicek}$ = 2621000000 (1/ft)
3. β_{mac} = 257090 (1/ft)
4. β_{ergun} = 2.094 x 10^4 (1/ft)
5. $\beta_{geertsma}$ = 2.434 x 10^7 (1/ft)
6. β_{liu} = 379.601 (1/ft)

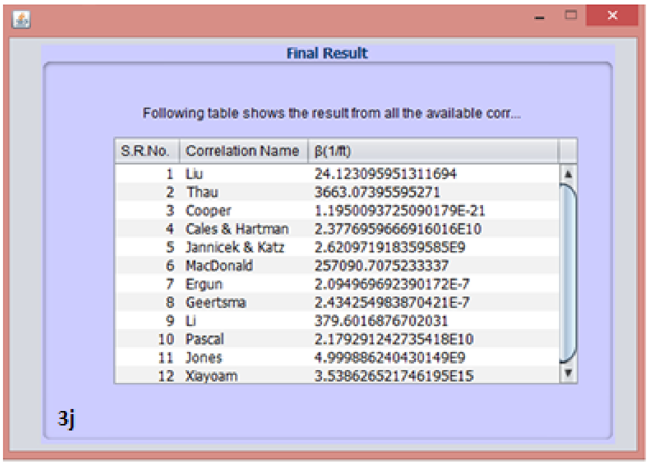
Select Yes if you wish to calculate the beta values by using other correlations (options).



3h: Selection of other set of correlations (k only). Option 03 is chosen for running the programme, Click Next.



3i: Output window for selected choice.
1. β_{Pascal} = 2.17 × 10^{11} (1/ft)
2. β_{Jones} = 4.99 × 10^9 (1/ft)
3. $\beta_{Xiayoam}$ = 3.53 × 10^{15} (1/ft)



3j: Final result.
1. β_{Liu} = 24.123 (1/ft)
2. β_{Thau} = 3663.07 (1/ft)
3. β_{Cooper} = 1.195 (1/ft)
4. β_{cales} = 23700000000 (1/ft)
5. $\beta_{jannicek}$ = 2621000000 (1/ft)
6. β_{mac} = 257090 (1/ft)
7. β_{ergun} = 2.094 × 10^4 (1/ft)
8. $\beta_{Geertsma}$ = 2.434 × 10^7 (1/ft)
9. β_{Liu} = 379.601 (1/ft)
10. β_{Pascal} = 2.17 × 10^{11} (1/ft)
11. β_{Jones} = 4.99 × 10^9 (1/ft)
12. $\beta_{Xiayoam}$ = 3.53 × 10^{15} (1/ft)

formation. The inbuilt set of correlations will calculate the required values of beta factor.

Discussion

Various empirical and theoretical correlations have been discussed in the paper to understand the Darcy and non-Darcy flow behavior in porous consolidated and unconsolidated formations.

The flow will be Darcy at low flow rates and a linear relationship will exists in between pressure gradient and velocity. At high flow rate conditions, the rapid change in the velocity as a function of pressure gradient and high molecular interactions in the porous media makes Darcy's law insignificant. So, a non-Darcy coefficient was introduced and added as a term to the Darcy's Equation. This combined Darcy and non- Darcy law (as first proposed by Forchheimer) is used as a single correlation for predicting flow behavior at high flow rate conditions.

By careful investigations and literature review, it has been observed that the beta factor or non – Darcy coefficient will be dependent on

Correlations	Beta Values Computed by Proposed Simulator (in 1/ft units)				
	C1	C3	C6	C9	C10
Pascal	2.17E + 11	2.95E + 11	7.43E + 11	1.71E + 11	2.02E + 11
Coles	23700000000	37800000000	1.68E + 11	16200000000	23100000000
Janicek	2621000000	3780000000	9725000000	2027000000	2411500000
Macdonald	257090	322130	439254	230626.7	245217.33

Table 5: Computed/calculated beta values by proposed simulator.

the rock properties like porosity, permeability, tortuosity, and specific surface area, grain and pore size.

After literature review, an algorithm has been prepared which gives a step wise step process to compute the non-Darcy coefficient by using existing correlations in the literature.

The prepared algorithm is converted and coded in a Java Script to create a working simulator. This simulator is capable of computing beta values or non- Darcy coefficient values for all porous formations. The key input parameters for running this simulator are permeability, porosity and tortuosity.

The robustness of the simulator was tested by using the data available in the literature. After running the application, it was observed that the computed beta values were completely matching with the available literature data with zero % level of difference. This shows that this simulator is robust and can be used for other set of data also.

This study gives a non–Darcy flow coefficient guideline which can be used to predict the pressure gradient, velocity and hence production rate at near well bore conditions. All the pressure disturbances and production rate change can be quantitatively calculated if the non-Darcy coefficient value is available.

Conclusion

It is challenging to characterize and predict the flow behavior in porous media at high flow rate or high Reynolds's Number. This makes Darcy's law inappropriate to use. A non-Darcy term if added to Darcy equation, can take away this inadequacy. This combined law or a single correlation can be used to predict the pressure profile and production rate at high flow rate. This non-Darcy term plays a very important role in predicting the pressure losses and flow in porous media. All the non-Darcy correlations suggested by various researchers have been carefully investigated and it has been observed that this term will be a function of rock properties mainly – porosity, permeability, tortuosity, pore size etc. Hence, these rock properties are integral part and key parameters for the computation of Non- Darcy Coefficient. An algorithm has been presented in the paper by using 12 different correlations. It was later coded and converted in to a robust simulator which will directly give the value of beta factor/non-Darcy coefficient after entering the required rock parameters. The obtained beta values can be very well used for predicting the flow behavior and production rate in the porous formations.

Acknowledgments

The Authors are thankful to Pandit Deendayal Petroleum University for continuous support and cooperation in the successful completion and publication of this review work.

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