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Novel Models with Memory for Flow of Share-Thinning Fluids in Porous Media during Polymer Flooding

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Abstract

The flow of aqueous polymeric fluids through porous media has been studied in the past mainly due to its importance in the areas of enhanced oil recovery (EOR). Past investigations focused on the flow of inelastic shear-thinning fluids and more complex viscoelastic polymers. Even when the bulk rheology of the aqueous polymer solution is known, there is still an issue of how this relates to the in situ rheology of the fluid. Because of the complexity of the geometric structure of porous media, the apparent viscosity is an aggregate or "upscaled" measure of viscous, elastic and extensional flow effects, and the matter of how this should be done has been of recent concern. For polymeric solutions, the apparent viscosity is a function of flow rate through porous media, and the flow rate is further correlated with the in situ shear rate within the porous medium. This flow rate may also be interrelated with the fluid memory in the pore network where mineral precipitation or other history of movement may delay the response of the in situ fluid. This delay can lead to restriction of the polymer flow through the pore throat. This paper attempts to eliminate these unsolved complexities of the fluid flow in porous media. To do so, mathematical models with memory are introduced to present the complex rheological phenomena combining the in situ shear rate and bulk rheology with fluid memory. The models are numerically solved and compared the results with existing models with experimental data, available in the literature. The models can be used in polymer flooding, reservoir simulation and characterization of complex reservoirs.

Keywords: Shear-thinning fluid, polymer flooding, fluid memory, porous media, reservoir rheology, numerical modeling, enhanced oil recovery.

Nomenclature

a	parameter in Carreau–Yasuda model, dimensionless
A	Cross sectional area of rock perpendicular to the flow of flowing fluid, m^2
k	Initial reservoir permeability, m^2
L	Length of a capillary or a core, m
n	power-law exponent for Carreau–Yasuda model, dimensionless
p	Pressure of the system, N/m^2
Q	$= Au =$ initial volumetric flow rate, m^3/s
q	fluid mass flow rate per unit area, kg/m^2s
t	Time, s
u	Darcy velocity ($= Q/A$), m/s

Greek Symbols

Δp	Differential pressure along a core or capillary of length L, N/m^2
α	Fractional order of differentiation, dimensionless
α_{SF}	Shape factor which is medium-dependent
$\dot{\gamma}$	Shear rate within the porous medium, $1/s$
$\dot{\gamma}_{pm}$	Apparent shear rate within the porous medium, $1/s$
μ	Fluid dynamic viscosity, $pa.s$
η	ratio of the pseudopermeability of the medium with memory to fluid viscosity, $m^3s^{1+\alpha}/kg$
ξ	A dummy variable for time i.e. real part in the plane of the integral, s
ρ	Single phase mass density, kg/m^3
Γ	Gamma function
ϕ	Porosity of the rock matrix, m^3/m^3
λ	Time constant in Carreau–Yasuda model, s

Subscripts

o	At zero share rate
x	Flow direction along x-in a Cartesian coordinate
app	Apparent
ref	Reference point
eff	Effective
∞	At infinite share rate

1. Introduction

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The flow and displacement of non-Newtonian and complex fluids (such as polymer gels and surfactants) in porous media is an important subject. This type of fluids include paint, slurries, pastes, and food substances, as well as heavy oils and foams in porous media. When oil recovery operation is done during water flooding, in addition to that polymeric solutions are often used to the aqueous phase to increase its viscosity. As a result, a more stable displacement of oil occurs during water injection. Polymers in solution may also be used in oil producing wells to block excessive water production from an aqueous high-permeability layer [1]. Polymers also help to initialize and stabilize fractures which increase the injectivity especially in water injection wells [1, 2]. Finally, the presence of surfactant in the water phase increases the oil recovery by lowering the surface tension between the aqueous and oil phases. It also decreases the residual oil saturation.

These polymeric fluids reveal complex behavior. Majority of the macroscopic properties of these fluids are time and shear rate dependent. Their reactions with oil, water, or the porous medium itself are also a factor [3, 4]. The precipitation and obstruction in the pores and pore throat of the porous medium may reduce the pore size and permeable path [3 – 5]. These phenomena decrease the permeability with time. Therefore, if permeability diminishes with time, the effect of fluid pressure at the boundary on the flow of fluid through the medium is delayed. The information of this effect over time in the fluid flow will continue if the medium (i.e. flowing fluid) holds a memory [5 – 7]. However, most of the current flow models in porous media have been developed for purely Newtonian and Non-Newtonian fluids where no model represents the fluid memory with the shear-thinning fluid models [8 – 13]. Most of the researchers have tried to relate the bulk properties of complex fluids to their behavior in a porous medium using a common approach consists of representing the medium by a bundle of parallel capillary tubes [1].

The majority of complex fluids used in oil field applications are non-Newtonian polymeric solutions demonstrating shear-thinning (pseudoplastic) behavior in solution. The bulk macroscopic properties of these solutions, mainly their viscosity/shear rate dependency, are well understood and characterized using established models. Ideally, one wishes to extend this knowledge to the flow of non-Newtonian fluids in porous media and predict their macroscopic behaviors without any further experimental work. Existing theoretical models as well as experimental findings are well established in the literature [8 – 13].

The present study addresses the shear rate and viscosity of polymeric complex fluid as a function of time and other related bulk properties of fluid and media itself where fluid memory has been incorporated to represent macroscopic and microscopic behavior of fluid and media in a more realistic way.

2. Mathematical model Development

2.1. Existing Model

The two main polymers used in the oil industry for hydrocarbon recovery are synthetic polyacrylamide (in its partially hydrolyzed form, HPAM) and Xanthan biopolymer gum. Bulk properties measurement of polymeric solutions is a standard and reliable experimental procedure. Therefore, researcher's efforts have been made to extend the laws of motion for purely Newtonian fluids (Darcy's law) to rheologically complex ones using easily measurable properties such as the shear rate/viscosity behavior. A bundle of parallel capillary tubes approach has been used to measure the macroscopic and microscopic properties of porous media. This approach leads to the definition of an average radius which is dependent on macroscopic properties of the medium such as porosity, absolute permeability, and some measure of tortuosity. The available mathematical models (such as power law, Carreau, or Cross models) to describe the fluid rheology have been developed to define viscosity and apparent shear rate from the use of the Darcy velocity [14 – 16]. Experimental results show that the shape of the apparent viscosity curve is similar to that of bulk shear rate. Most of experimental works had been performed by Xanthan biopolymers whose experimental results are available in the literature [9, 14 – 17] where they tried to find the shape factor, α_{SF}. For the porous media, Chauveteru's form of the definition of porous media wall shear strain rate or in-situ shear rate is [4, 10, 18 – 21]

$$\dot{\gamma}_{pm} = \frac{\alpha_{SF}\, u}{\sqrt{k\,\varphi}}. \quad (1)$$

In the above equation, α_{SF} represents shape factor. In the context of polymer flooding (part of enhanced oil recovery schemes), in-situ rheology depends on polymer type and concentration, residual oil saturation, core material and other related properties is addressed in the available literature [4, 12, 17, 21 – 23]. A brief discussion has been outlined by Lopez [24].

There have been developed several constitutive equations in the past that capture the full bulk rheological behavior of pseudoplastic solutions [21]. To model the bulk rheology of the non-Newtonian fluid, Escudier et al. [24] performed a set of experiments on Xanthan gum. Lopez [24] showed that Carreau-Yasuda, Cross and Truncated Power-law models behave almost same when they presents the bulk rheology (e.g. effective viscosity) of shear thinning fluid. Therefore, Carreau-Yasuda model is considered in this study and is used to develop and analyze the memory model in bulk rheology. Carreau-Yasuda model may be written as [1, 4, 9, 15, 19, 24]

$$\mu_{eff} = \mu_\infty + \frac{(\mu_0 - \mu_\infty)}{[1 + (\lambda\,\dot{\gamma})^a]^{\frac{n}{a}}} \quad (2)$$

2.2. Mathematical Model with Fluid Memory

The exact form of the shear stress-shear rate (stress-stain) relationship depends on the nature of the polymeric solution. Therefore, recently, a question is always coming out about the effect of memory on rock/fluids in porous media when predicting oil flow outcomes. Hossain and Islam [25] have reviewed the existing complex fluid flow models with memory available in literature. None of them has focused the shear thinning fluid models which may couple with fluid memory. Recently Hossain and coauthors [4, 6 – 7] have developed a model which represents a more realistic rheological behavior of fluid and media. They have developed a stress-strain relation coupling the macroscopic and microscopic properties with memory. They also did not consider the polymeric fluid properties in porous media. However, the conventional practice is to consider the Newtonian fluid flow equations as ideal models for making predictions. Even non-Newtonian models focus on what is immediately present and tangible in regard to fluid properties. This paper argues that the intangible dimension of time and other fluid and media properties can be coupled to demonstrate the more complex behavior of shear thinning fluids in porous media.

In practical macroscopic point of view, several authors [4, 13, 26, 27] have reported that the apparent viscosity of polymer solutions within various porous media are usually bead packs, sand packs and outcrop sandstone rocks. Referring to them, the apparent viscosity for the polymeric solutions can be defined from Darcy's law as follows:

$$\mu_{app} = \frac{k\,A}{Q}\,\frac{\Delta p}{L} \tag{3}$$

For polymeric solutions, the apparent viscosity μ_{app} is a function of flow rate through the porous medium [13, 22], and the flow rate is further correlated with $\dot{\gamma}_{pm}$, the in situ shear rate within the porous medium, which is expressed as Eq. (1). In this simple equation, however, it is not obvious why $\dot{\gamma}_{pm}$ should vary linearly with the Darcy velocity, due to the complexity of the internal flows within the porous medium. The central theoretical problem of in situ rheology is therefore to establish clearly how the local (microscopic or pore-scale) rheology in a single pore relates to the aggregated or average bulk property as expressed by the apparent viscosity discussed above. Hence it is the effect of this local behavior, mediated through the interconnected network of pores in the porous medium to the macroscopic scale that must be found. Therefore it is necessary to clarify how the local (microscopic or pore-scale) rheology relates to the average bulk rheology as expressed by the apparent viscosity.

To investigate the local phenomenology, we may introduce memory effect for the fluid complex rheological properties. In this regard, fluid precipitation of minerals and temperature may be considered. However, some fluids carry solid particles that may impede some of the pores. The precipitation and obstruction may reduce the pore size and thus decrease the permeability in time. Some fluid may have chemically reacting behavior with the medium which may enlarge the pore size. These phenomena let the researcher to think about the local mineralization and permeability changes which lead for a spatially variable pattern. Therefore, if permeability diminishes with time, the effect of fluid pressure at the boundary on the flow of fluid through the medium is delayed. The information of this effect over time in the fluid flow will continue when the medium (i.e. flowing fluid) holds a memory.

Hossain and coauthors [4, 6 – 7] initiated a rate equation model to study the flow of these fluids with memory. Caputo [3, 5] modified Darcy's law by introducing the memory represented by a derivative of fractional order of differentiation which simulates the effect of a decrease of the permeability in time. If the fluid flows in x-direction, the mass flow rate equation may be written as [3 – 7]:

$$q_x = -\eta\,\rho_0\left[\frac{\partial^\alpha}{\partial t^\alpha}\left(\frac{\partial p}{\partial x}\right)\right] \tag{4}$$

where

$$\frac{\partial^\alpha}{\partial t^\alpha}[p(x,t)] = \frac{1}{\Gamma(1-\alpha)}\int_0^t (t-\xi)^{-\alpha}\,\frac{\partial}{\partial \xi}[p(x,t)]\,d\xi,$$

with $0 \le \alpha < 1$

The memory function introduced in Eq. (4) implies the use of two parameters, namely α and η. These two parameters are used instead of the permeability and viscosity in conventional Darcy's law. In Eq. (4), pressure gradient is negative and this has a decreasing slop [4]. Therefore, Eq. (4) can be written for fluid velocity which is related to pressure gradient as:

$$u = \frac{\eta}{\Gamma(1-\alpha)}\int_0^t (t-\xi)^{-\alpha}\,\frac{\partial^2 p}{\partial \xi \partial x}\,d\xi \tag{5}$$

Substituting Eq. (5) in Eq. (1)

$$\dot{\gamma}_{pm} = \frac{\alpha_{SF}}{\sqrt{k\,\varphi}}\,\frac{\eta}{\Gamma(1-\alpha)}\int_0^t (t-\xi)^{-\alpha}\,\frac{\partial^2 p}{\partial \xi \partial x}\,d\xi \tag{6}$$

The above mathematical model provides the effects of the polymer fluid and formation properties in one dimensional fluid flow with memory and this model may be extended to a more general case of 3-Dimensional flow for a heterogeneous and anisotropic formation.

Several workers [20, 28] used almost same expression to represent the apparent shear rate as an effective shear. Moreover, Savins [26, 27] refers this problem as "scale up". Sorbie et al. [20] review some of the alternative approaches to this problem. In this study, we ignore this shifting or scale up problems due to a constant factor involvement. This will not affect the big picture of the effective or apparent viscosity model. Therefore, to analyze complexity of the rheology of the rock and fluid, the memory function is used to describe the viscosity and permeability in the shear-thinning fluid. As a result, the model presented in Eq. (6) is applied in Eq. (2) which reduces to the form:

$$\mu_{eff} = \mu_\infty + \frac{\mu_0-\mu_\infty}{\left[1+\left(\frac{\lambda\,\eta\,\alpha_{SF}}{\sqrt{k\,\varphi}}\,\frac{\int_0^t (t-\xi)^{-\alpha}\frac{\partial^2 p}{\partial \xi \partial x}d\xi}{\Gamma(1-\alpha)}\right)^{\alpha}\right]^{\frac{n}{\alpha}}} \tag{7}$$

3. Results and discussion

To solve the convolution integral of Eqs. (6) and (7), a reservoir of length (L = 5000.0 m), width ($W = 100.0\,m$) and height, ($H = 50.0\,m$) have been considered. The porosity and permeability of the reservoir are 30% and 1×10^{-14} to $13.5\times10^{-14}\,m^2$ (10 md to 135 md), respectively. The reservoir is completely sealed and produces at a constant rate where the initial pressure is $p_i = 27579028\,pa$ (4000 psia). The fluid is assumed to be Xanthan gum, with the properties $c = 1.2473\times10^{-9}\ 1/pa$, $\mu_0 = 13.2\,pa\,s$. The initial production rate is $q_i = 8.4\times10^{-9}\ m^3/s$ and the initial fluid velocity in the formation is $u_i = 1.2\times10^{-5}\ m/s$. The fractional order of differentiation, $\alpha = 0.2-0.8$, $\Delta x = 1000\,m$, and $\Delta t = 7.2\times10^4\,s$ have also been considered. The computations are carried out for $\mathrm{Time} = 40\,months$. In solving this convolution integral with memory, trapezoidal method is used. All computation is carried out by Matlab 6.5.

In this paper, we focused on the dependence of the shear rate on porosity, permeability, shape factor and flow velocity which is related to the effect of fluid memory. To solve the Eq. (6), $\eta = 0.343249$ and $\alpha_{SF} = 1.25$ are used in numerical computation [4]. In solving the proposed modified Carreau-Yasuda model presented in Eq. (7), the Xanthan gum fluid viscosities at low (μ_0) and high shear rate (μ_∞) are considered as 13.2 pa s and 0.00212 pa s respectively [9]. The power-law index, *n* and the time constant, λ are taken as 0.689 and 60.7 s respectively [9]. Here, the diminishing permeability in the pore space and throat of the reservoir formation are varied within the range as mentioned before to considered fluid memory of the flowing shear thinning fluid.

3.1. Shear Rate Dependency on Different Parameters

3.1.1. Shear Rate Dependency on Permeability for Different α Values

Figure 1 presents the variation of in situ or apparent shear rate with permeability for different α values. These are the nonlinear profiles for different α values. These curves show that as permeability increases, the in-situ shear rate increases slightly for a very tight reservoir. This trend reduces when α value increases. This indicates that when memory effect is dominant in a tight reservoir, it tries to restrict the fluid movement. However, as permeability increases, shear rate start to decrease up to a certain range of permeability values. The range is 45 md – 55 md. The fixed value depends on α value. After this transient permeability level, shear rate increases with the increase of permeability value. The whole characteristics and trend of the curves are same for all the α values. The memory of fluid has a great influence on in situ shear rate. For the same permeability value, the in situ shear rate decreases with the increase of α value at a rage of up to 0.4 and after that it increases with the increase of α value. The magnitudes of the in situ shear rate variation are more dominant when fluid memory (α value) increases. Moreover, we already focused earlier that the variable permeability is one of the cause of fluid memory. The initial decrease and then increase of shear rate variation with permeability indicates that fluid take sometime or delay to move after feeling pressure or force to move. This delaying of fluid movement is nothing but a microscopic property of the viscoelastic fluid. This phenomenon is defined by fluid memory [4, 6 – 7]. Therefore the fluid movement can be characterized by the memory effects.

3.1.2. Shear Rate Dependency on Shape Factor for Different Permeability

The available literature [1, 9, 15, 18, 19, 28] reported that the value of α_{SF} lies in the range of 1.0 – 14.1. This variation depends on the type of porous media. This may vary from 1.0 in regular unconsolidated packs up to 10.0 in consolidated sandstone [19]. The experimental results show that α_{SF} is in the range of 1.1 – 2.5 for ballotini beads and 1.9 – 9.1 for sandstone cores [20]. Therefore, to analyze the dependency of in situ shear rate with α_{SF}, it has been considered the value of α_{SF} in the range of 1.0 – 15.0.

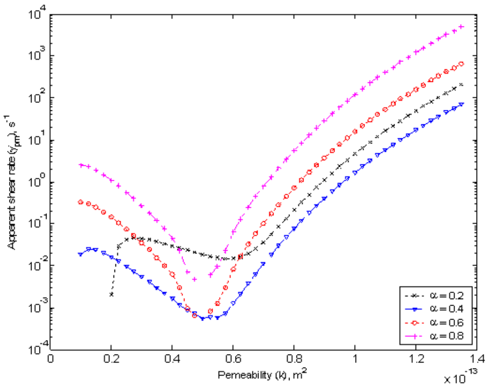

Fig. 1. Variation of apparent shear rate with permeability of the porous media for $\alpha = 0.2$ to 0.8

Figure 2 shows the variation of apparent shear rate with shape factor, α_{SF} for $k = 70\ md, 80\ md$ and $90\ md$ at a α value of 0.2. The in situ shear rate verses shape factor cure shows a linear relation that has an increasing trend with the increase of shape factor. The affects of shape factor on apparent shear rate is more sensitive at higher permeability where the range of variation of $\dot{\gamma}_{pm}$ is more. On the other hand, it is less sensitive at lower permeability.

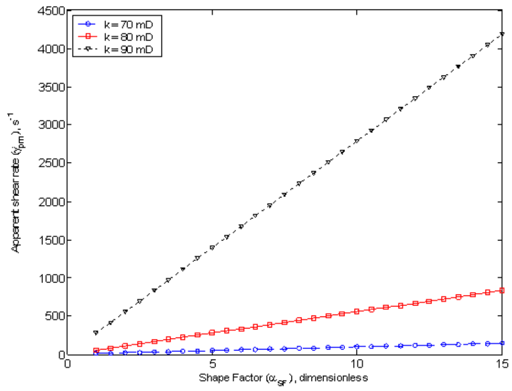

Fig. 2. Variation of apparent shear rate with shape factor for $k = 20\ md$ and $60\ md$

3.1.3. Shear Rate Dependency on Shape Factor for Different Porosity

Figure 3 shows the variation of apparent shear rate with shape factor, α_{SF} for different porosity of the formation at a α value of 0.2 in a semi log plotting. The present plotting trend of the cure shows a non-linear type however this is a complete linear plotting in a Cartesian graph paper. For a tight reservoir (low porosity), shear rate is much higher comparing with medium or highly porous media for the same shape factor. Shear rate increases with the increase of shape factor for all porosity.

3.1.4. Shear Rate Dependency on Flow Velocity for Different α Values

To investigate the effects of flow rate on shear rate with memory, porosity and permeability are considered as 30% and 70 md respectively. Flow velocity, u is varied in the range of 1.0×10^{-5} to $13.5 \times 10^{-5}\ m/s$.

Hossain et al (2009): Share-thinning fluids

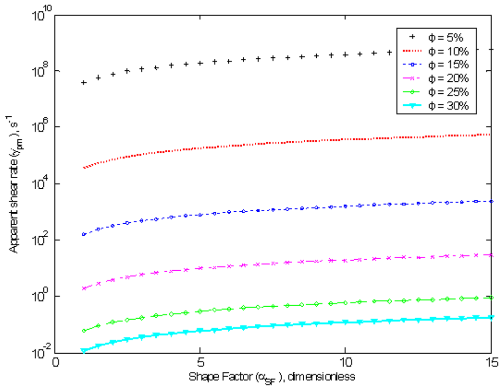

Fig. 3. Variation of apparent shear rate with shape factor for $\varphi = 20\%$ and 40%

Figs. 4 – 6 present the variation of in situ shear rate with flow velocity for different α values. Shear rate decreases with the increase of flow rate at low velocity range. There is slide faster decrease in the range of velocity increment of 1.5×10^{-5} to $2.0 \times 10^{-5}\ m/s$. After this velocity range, shear rate increases faster with the increase of flow velocity which is an asymptotic variation. This trend continues until the velocity of $5.5 \times 10^{-5}\ m/s$ and again it starts to reduce after this velocity. The relationship between in situ shear rate and flow rate is nonlinear trend whereas Perrin et al. [29] showed that the average in situ shear rate varied linearly with the flow velocity. This non-linearity is only due to the memory effects on fluid flow behavior. Moreover, the shape and trend of the cures are similar for all the α values except the magnitude of the shear rate values which also leads to the existence of fluid memory on shear-thinning fluid. Here, shear rate increases with the increase of α values.

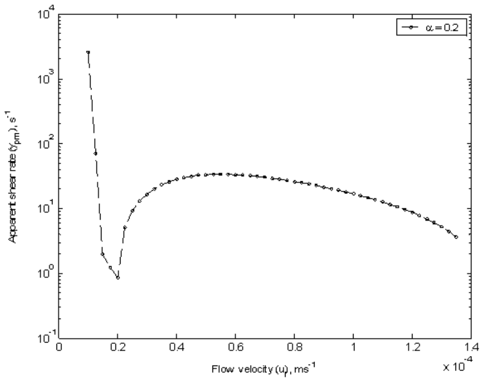

Fig. 4. Variation of apparent shear rate with flow velocity for $\alpha = 0.2$

Fig. 7 presents the conventional in situ shear rate model (Eq. (1)) available in the literature. The nonlinear trend of the $\dot{\gamma}_{pm}$ curves (Figs. 4-6) are due to the memory dependency of flowing fluid which did not captured by the Perrin et al. [13] and other researchers. So, it can be concluded that fluid memory has an influence on the shear thinning fluid and microscopic rheological behavior of the fluid may be characterized by this memory effect.

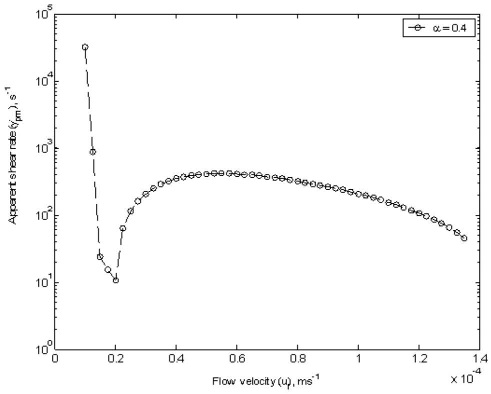

Fig. 5. Variation of apparent shear rate with flow velocity for $\alpha = 0.4$

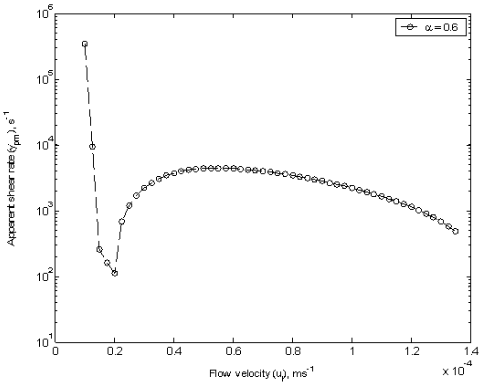

Fig. 6. Variation of apparent shear rate with flow velocity for $\alpha = 0.6$

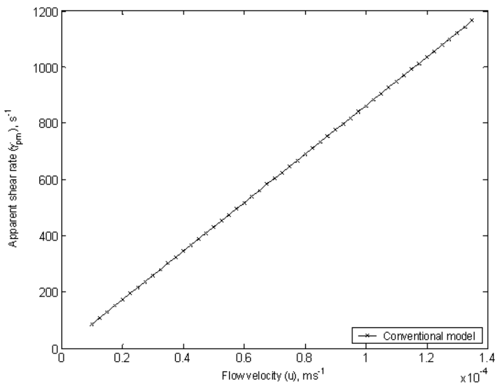

Fig. 7. Variation of shear rate with flow velocity for the model presented in Eq. (1).

3. Conclusion

In this study, two models are proposed to characterize the rheological behavior with memory for the shear-thinning fluids. These models are established with the existing experimental data and compare with the conventional model. The shear rate-flow velocity has a non-linear variation which may draw the attention of the researchers to think about something else why the conventional linear relationship is violating in this case. The answer should be as "fluid movement can be characterized by the memory effects". In this paper, we focused on the dependence of the shear rate on porosity, permeability, shape factor and flow velocity which is related to the effect of fluid memory.

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