PS Formation Damage Disaggregation in Gas Well and Sensitivity Reservoirs from Build Up Well Test*

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Search and Discovery Article #41933 (2016)**
Posted November 14, 2016

*Adapted from extended abstract based on a poster presentation given at AAPG 2016 International Convention and Exhibition, Cancun, Mexico, September 6-9, 2016

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Abstract

The main objective of the total formation damage disaggregation is to identify which are the relevant components of this damage. This paper presents a methodology for disaggregation of formation damage in three components: non-Darcy flow, geomechanical and mechanical damage, considering only a buildup test. Two steps make up methodology: first, total skin is broken up in non-Darcy flow and another damage, (called prime damage), interpreting buildup test with the Spivey's model. Then, prime damage is separated in geomechanical and mechanical damage using a permeability modulus based model. The methodology has been applied to wells in the Colombian Foothills field, which have presence of natural fracture systems and show sensitivity to stresses, as well as high flow rates. Results show that one or two damages prevail in the wells analyzed. On the other hand, well test interpretation permits characterizing the near wellbore area geomechanically and from a point of view of non-Darcy flow. Contribution of this formation damage disaggregation methodology is to identify the major damage components, allowing choice the most appropriate stimulation operation which could be apply on the well to improve the well productivity. Besides, this methodology seeks decrease the uncertainty in damage remediation with a minimum amount of information.

Introduction

Conventionally, formation damage has been associated with the presence of a low flow zone located near the borehole wall (Porter, 1989) due to any process which cause a reduction in the productivity and/or injectivity (Qutob and Byrne, 2015). However, several factors can significantly affect well productivity and the decision about the appropriated choice of stimulation operation to be made on the well for restoring its productivity. For instance, the pore pressure changes may induce a geomechanical response of reservoir affecting it's flow capacity (Ju, 2014), or a high flow velocity may generate a turbulent flow or damage due to non-Darcy flow (Lee et al., 2003). The main idea of the total formation damage disaggregation is the identification of major damage components that allow selecting the most appropriate stimulation operation that could be applied on the well to restore the well productivity and decrease the uncertainty in damage remediation.

The disaggregation procedure of total formation damage applied in this work are obtained using Civan's hypothesis, related to independent contribution of damage (Civan, 1996) and applying two steps: In the first one, well test is interpreted using Spivey et al. methodology; here total skin is divided in two parts, one associated to the non-Darcy flow and another skin factor different to this effect. In the second one, ATS software has been applied to disaggregate the formation damage component, which it is not, associated with no Darcy effects; this component is separated in both mechanical and geomechanical skin factors. Therefore, total skin is discretized in three components: non-Darcy, geomechanical and mechanical formation damages. The mentioned procedure has been applied to wells located in the eastern Colombian's foothill, one zone considered with high geomechanical sensitivity, high stress state and with presences of non-Darcy flow.

Background

For decades, formation damage has been studied widely because of its impact on the well's productivity performance. Overarching framework has been considered that the formation damage may be generated by any activity made on the well or reservoir that induces: changes in permeability, variations in relative permeability (Di Giorgi, 1990) or changes in the viscosity of reservoir fluids; even if change of porosity could be other factor causing formation damage (Qutob and Byrne, 2015). In particular, the pore pressure changes increase depletion process in the reservoir, which generates permeability variations (Pedrosa, 1986) by geomechanical response of the reservoir (Raghavan and Chin, 2004). A second way of categorizing these damage mechanisms could be mechanical, chemical and biological process, which induces formation damages (Qutob and Byrne, 2015).

Civan (1990) proposes a set of models to describe each of these damages and others like particle deposition and entrainment by hydrodynamic processes. In addition, Civan introduces conceptual aspects of damages related to dissolution, corrosion and precipitation, which are generated by physiochemical interaction of solid with a liquid, as so as, damages associated with nucleation processes and biological particles. Di Giorgi (1990) makes a systematic study of the formation damage causes, which makes up for five sequential steps: identification, duration, intensity, effect and impact of damage over productivity.

On the other hand, Ostensen (1986), Vairogs, et al. (1971) show examples of studies that analyze the behavior of reservoir permeability with changes in pore pressure. Moreover, Pedrosa proposes an approximation that includes the dependence of permeability with pore pressure into the diffusivity equation and obtains their respective solution (Pedrosa, 1986). Raghavan and Chin consider a set of both permeability and porosity correlations as a function of pressure and use a mass balance equation to simulate the behavior of formation damage with pressure variations (Raghavan and Chin, 2004). Ju (2014) developed a simple elastic and elasto-plastic deformations model, which quantifies the permeability changes near the wellbore. (Addis, et al., 2010) present discussions relate to geomechanical considerations of wellbore orientation, in-situ stress systems, and connectivity hydraulic fractures with the natural fracture system, for multi-staged fracturing. Similarly, Vazari (1988) exposes aspects related to wellbore stress changes caused by factors such as: drilling, mud cake and far-field tensor stress, coupling both equilibrium's and Darcy's equations and considering the Duncan-Chan failure criterion. Alcalde and Teufel (2006) propose a rock/fluid flow coupled model, which describes deformation near to wellbore and its impact in the permeability variation.

Additionally, in a gas well, the non-Darcy skin presences could be generated, when high flow rate is present in the near wellbore (Lee et al., 2003; Sabet, 1981). Non-Darcy flow can reduce well productivity between 5% and 30% and combined with other factors such as multiphase flow, (Spivey et al., 2004) this effect could be greater according to Zeng and Grigg (2006). However, phenomena like turbulent flow, inertial flow, high velocity, etc, are consider as non-Darcy skin and they represent the microscopic inertial effect, specifically, non-Darcy flow behavior is due to the increase of the microscopic viscous force at high flow velocities. Two types of criteria, the Reynolds number and the

Fochheimer number, have been used to identify the presence of non-Darcy flow, but the Fochheimer number is recommended as the criterion for non-Darcy flow in porous media (Zeng and Grigg, 2006).

Usually, the non-Darcy skin is determinate by performing multi-rate test, plotting skin factor vs. flow rate, allowing determinate the total skin and the non-Darcy flow coefficient, from a straight-line fit through data. Also correlations (Li and Engler, 2001) and core analysis (Zeng and Grigg, 2006) can be used to estimate turbulence coefficient β, which is proportional to non-Darcy flow coefficient, and therefore to the non-Darcy skin factor. To characterize the inertial effects, the Fochheimer equation has been utilized to describe the non-Darcy flow in a porous media. In addition, Brinkman equation could be used to describe the macroscopic shearing effect between the fluid and the pore wall that can be present in the system (Zeng and Grigg, 2006). In this study, we consider the type curves generate by Spivey et al. (2004), which permit to recognize and estimate the non-Darcy skin factor from a log-log diagnostic plot of pressure change and pressure derivative, using a single buildup test.

Theoretical Aspects

The procedure most extensively used to determine the formation damage is the well test analysis, which is described by authors like Mathews and Russell (1967) and Lee et al., 2003. These procedures are called conventional methods. On the other hand, Osorio, Chen and Teufel present the mathematical development for coupling geomechanical behavior of the reservoir and flow in porous media, as well as results obtained to apply the computational model to particular cases (Osorio, et al., 2002). In this case the flow of fluid through of reservoir decreases pore pressure of the media, which affects the permeability affecting again pore pressure. So, this procedure can be used to capture the geomechanical behavior of the system, taking like based a build-up well test.

Non-Darcy factor skin. From the point of view of non-Darcy flow, there are several forms to characterize this kind of skin factor. Ordinarily, the turbulent flow is modeled by Fochheimer's equation as (Civan, 1990); (Zeng and Grigg, 2006).

$$-\nabla\Phi = \frac{\mu}{k}v + \frac{1}{\beta}v^2 \quad (1)$$

Well test analysis can be utilized to obtain the non-Darcy skin factor. Generally, a multi-rate test allows building a plot of skin factor vs. rate. After using the approach of Ramey

$$s' = s + Dq_{sc} \quad (2)$$

Where ***s'*** is the total skin, $\boldsymbol{Dq_{sc}}$ is damage associated to non-Darcy flow, where ***D*** is the non-Darcy flow coefficient and ***s*** is a factor skin compose by both pressure changes skin and mechanical skin.

Considering that, the available information is the main problem in the moment to get the damage factor; Spivey et al. propose a model to generate type curves for non-Darcy flow, which is based on convolution integral and mass conservation law. Applying, these concepts at the sandface is possible to obtain an expression that related the sandface pressure, p_{sf} , wellbore pressure, p_w , and sandface flow rate given by

$$p_{wD} - p_{sfD} = sq_{sfD} + D_D q_{sfD}^2 \tag{3}$$

In addition, it is necessary know t_D, which depends of type of well test analyzed, for a buildup test (Spivey et al., 2004)

$$t_D = -C_D \left[s\ln(q_{sfD}) - 2D_D (1 - q_{sfD}) \right] \tag{4}$$

Where the dimensionless variables are defined as follow

$$p_{sfD} \equiv \frac{kh(p_i - p_{sf})}{141.2 q_{sc} B\mu} \tag{5}$$

$$p_{wD} \equiv \frac{kh(p_i - p_w)}{141.2 q_{sc} B\mu} \tag{6}$$

and

$$\mathrm{D_D} \equiv \mathrm{Dq_{sc}} \tag{7}$$

With $0 \le q_{sfD} \le 1$, we are interested in the development of a procedure such as those presented by Spivey et al (2004). In his study, two parameters to characterize the type curve are defined

$$\alpha_{\mathrm{ND}} \equiv \frac{\mathrm{D_D}}{\mathrm{s + D_D + 0.5ln(C_D)}} \tag{8}$$

and $C_D e^{2s'}$.

Factor skin by pressure changes. The relevant theoretical aspects related to geomechanics are based on both diffusivity and Pedrosa's equations. Thus, permeability changes by pressure variations as quantified through the Pedrosa's equation is as follows

$$k = k_i e^{-\gamma_D p_D} \tag{9}$$

where k_i is permeability at reference pressure, e.g. reservoir pressure; P_D is defined in the equation (6) and γ_D is the dimensionless permeability's modulus given by

$$\gamma_D = 141.2\frac{q\mu B}{kh}\gamma \tag{10}$$

where γ is the permeability's modulus. On the other hand, the diffusivity equation is as follows

$$\frac{1}{r_D}\frac{\partial}{\partial r_D}\left(r_D\frac{\partial P_D}{\partial r_D}\right) = \frac{\partial P_D}{\partial t_D} \tag{11}$$

where the dimensionless variables are given by

$$r_D = \frac{r}{r_w} \tag{12}$$

$$t_D = 2.64x10^{-4}\frac{kt}{\phi\mu c_t r_w^2} \tag{13}$$

Civan's hypothesis. Civan (1996) presents a multi-purpose formation damage model, which is able to simulate the chemical, physicochemical, hydrodynamic, thermal and mechanical damage, rock-fluid and fluid-fluid interaction. The model is a combination and generalization of several approaches reported in the literature. A consequence of this model is that total skin factor is a contribution of different formation damages generated by the interaction above mentioned. So, the total skin factor can be written as

$$s' = \sum s_i \tag{14}$$

In our case, the total skin factor is considered as a contribution of three damages: mechanical, s_m, due to permeability changes due to pressure changes, s_p, and non-Darcy, Dq_{sc}, so

$$s' = s_m + s_p + Dq_{sc} \tag{15}$$

Where $s = s_m + s_p$.

Methodology

The formation damage disaggregation involves two procedures or interpretations: one allows obtain non-Darcy damage and other damage. Then, this last damage component is disaggregated in both mechanical damage and formation damage due to pressure changes. Coming up next procedures are described.

Non-Darcy skin factor estimation. The procedure to estimate the non-Darcy factor skin, taking into account that $0 \leq q_{sfD} \leq 1$

a) First, it proceeds to read the pressure data over time obtained from the buildup test ran in the well. Parallel, ranges of values for the permeability k and non-Darcy skin factors $\boldsymbol{D_D}$ are assumed for making an adjustment of these data.
b) Taking into account the input of the previous point, from the initial test data dimensionless coefficient storage, $\boldsymbol{C_D}$, is calculated.
c) Noting that for a buildup test, in the sandface at the shut in moment both total damage is equal to dimensional wellbore pressure ($s' = P_{wD\,\Delta t=0}$) and rate across sandface is the unit, ($q_{sfD\,\Delta t=0} = 1$), i.e., $s = s' + D_D$. Therefore, $\boldsymbol{s}$ can be estimated at the shut in moment.
d) After, $\boldsymbol{q_{sfD}}$ (for each well test point) is estimated following an iterative procedure using the equation (4).
e) Posteriorly, $\boldsymbol{P_{wD}}$ and $\boldsymbol{t_D}$ are calculated using the equations (6) and (13), respectively and assuming that $p_{sfD} = 0$ for the buildup well test (Spivey et al., 2004).
f) Thereafter, dimensionless well pressure, $\boldsymbol{P_{wD}}$ is calculated with the equation (3) and the data found in the above steps. Subsequently, the wellbore pressure $\boldsymbol{P_{wf}}$ can be achieved.
g) Now, the steps d through f are repeated for all well test data.
h) When the vector of wellbore pressure $\boldsymbol{P_{wf}}$ is found, this vector is compared with actual wellbore pressures, which generates a relative error related to both one permeability value and one non-Darcy factor, initially suspected.
i) For last, values of permeability and non-Darcy skin factor are changed, and the steps b through h are repeated until to get the best matching.

In consequence, the skin factor by effects different to the non-Darcy skin, the permeability, the non-Darcy skin factor and dimensionless storage coefficient are estimated applying the first procedure.

Skin factor by pressures changes estimation. The procedure to estimate both mechanical damage and skin factor due to permeability changes by pressure changes, consider the equations (8) through (13). An analytical transient software (ATS) was developed to make it. ATS allows interpreting the well test using the solution of diffusivity equation in the Laplace space, to return after the pressure in the physical space applying the Sthefest's procedure, passing by the dimensionless space. The steps to obtain the factor skins mentioned are:

a) In principle, it proceeds to read the pressure data over time obtained from the buildup test ran in the well of study. As in the first procedure, range of values for the permeability modulus $\boldsymbol{\gamma}$ and mechanical skin factors are defined to make a matching of these data.
b) One couple of values of mechanical skin and permeability modulus is selected, then for the first time of the well test, ATS solves the equation (11), in the Laplace space. The Sthefest's procedure to obtain the inverse Laplace transform is applied; here, the solution belongs to the dimensionless space. Therefore, it is necessary use the equation (6) to obtain the pressure in the physical space.
c) Then, the procedure are spread over all well test times, obtaining a set of pressure values, which are compared with actual pressure.

d) Steps b and c are repeat until obtain a minimum error value between both actual and calculated pressure.

In accordance with above, a skin mechanical factor value and a permeability modulus are obtained. Now, considering the equation (15) is possible estimate the factor skin due to pressure changes, simply as a difference of total skin and both non-Darcy and mechanical skin factors. In addition, it is important mentioned that others properties, that characterize the reservoir, as the permeability, wellbore storage coefficient and permeability modulus are estimated. Next section presents the validation of the methodology and two cases, where this procedure was applied.

Results and Discussion

Primarily, for the wells studied the non-Darcy disaggregation is presented, showing two procedures: one related to type curve method and another, using the regression way. After that, both mechanical and skin factor due to pressures changes results are calculated. Wells belong to one field located in the Colombian's foothill.

Well A Case

Well A had a gas flow rate of 14000 Mscf before the PBU test and a net thickness of 350 ft, distributed between three different perforated formations. The PBU data was taken, with a production time of 34.2 hours. Figure 1 shows the results of the derivative analysis carried out through the methodology of Spivey. Curve type characterized by $C_D e^{2s'} = 1.2 \times 10^{138}$ and their respectively family of curves identify by α_{ND} parameter are plotted, considering step of α_{ND} equal to 0.2, where $0.0 < \alpha_{ND} < 0.8$. In addition, the derivative curve of the PBU is plotted here.

In Figure 1 is observed that, the derivative as well as the differential of pressure (ΔP) values match with the type curve correspondent to $\alpha_{ND} = 0.4$, it implies that in well A, there are turbulent flow. Although, one non – Darcy skin factor value has been obtained, the accuracy of this value only is corroborated by visual adjustment of both type and derivative curves. In consequence, it is possible to apply the regression methodology and get a relative error of 0.30% that indicates how close the simulated pressure curve is to actual pressure curve. This matching process between the pressures mentioned are shown in Figure 2, where time scale is logarithmic and pressure scale is normal. Other parameters, which characterize the reservoir, are present in Table 1.

Results of type curve and regression are shown in Table 1. Values of characterization of type curve family, α_{ND}, the $C_D e^{2s'}$ parameter and the error are presented. The α_{ND} values (0.4 and 0.52 obtained by both procedures) indicate the presence of non-Darcy skin, as well as wellbore storage effects, which are corroborated by the values $C_D e^{2s'}$ parameter ($1.23 \times 10^{+138}$ and $6.44 \times 10^{+132}$). Other variables can be deducted of this interpretation. The dimensionless wellbore storage coefficient, C_D, the total skin factor, s', the non-Darcy flow coefficient, D, the factor skin compose by both pressure changes skin and mechanical skin s and the Darcy skin D_D.

Excepting C_D, which ordinary shows a difference of one order of magnitude, when are obtained by regression and Spivey's type curve, in general the parameters presented in Table 1 have the same order of magnitude and the total skin factor, ***s'*** is similar to both methods.

After that, second methodology referent to both pressure changes skin and mechanical skin disaggregation was carried out using ATS software. Table 2 presents results obtained. Results show that the well A, has a wellbore storage dimensionless coefficient of 2000, which is in the same magnitude order than value estimate with Spivey regression procedure (see Table 1). From elsewhere, the drainage area of well A is sensitivity to changes to pressure owing to the permeability modulus value is high, equal to $1.29x10^{-3}$ *1/Psi*, which is characteristic of stress sensitive formations. Finally, the mechanical skin s_m is minor than s, the sum of pressure changes and mechanical skins, which implies that there is a pressure changes skin component different to zero. In fact, it corroborates the sensitivity to stress changes of the drainage area of well A. Therefore, using the Civan's hypothesis, equation (15), is possible to obtain the skin by pressures changes, so $s_p = 69\text{-}30$, which indicates that $s_p = 39$. Table 3 shows the disaggregation skin summary of the Well A. In addition, a percentage value respect to total skin is presented.

Results in Table 3 indicate that non-Darcy skin factor is the main component that contributes to total skin factor, being its contribution equal to 54% to total skin: Second contribution to total formation damage is the skin by pressure changes with an influence of 26% and third, is the mechanical skin with 20%. Question is what to do with this information. Answer is as follow. Initially, it is crucial identified which is the damage that is due to remediate first, with the purpose does not increase the others damages. After that, it is important to choose the remediation stimulation to remove the main component damage. Third, the procedure is repeat to others damage. In particular, if the flow rate is decreased, it is possible to remediate the non-Darcy flow, however that wellbore pressure increase, which causes that the skin by pressure changes decrease, i.e., only the modification of flow rate would be eliminate both factor skins in the Well A.

Well B Case

The buildup test in Well B had a production time of 41 hours, a flow rate of 45500 *Mscf* before the test and a net thickness of 610 ft, distributed between four different perforated formations. The derivative analysis carried out through Spivey's methodology is shown in Figure 3. Results displayed a α_{nD} coefficient of 0.2, which indicates that this well is slightly affected by turbulent flow effects and non-Darcy flow damage.

In addition, the regression procedure presented in Figure 4 show the adjustment of actual and simulated pressures. Results of procedures, Spivey's type curve and regression are in Table 4. Values of characterization of type curve family, α_{ND} , $C_De^{2s'}$ parameter and the error are presented. The α_{ND} values are 0.2 and 0.13, respectively, showing the existence of one small non-Darcy skin component; however, there is wellbore storage presence, which is validated by the values $C_De^{2s'}$ parameter ($3.17x10^{+16}$ and $1.54x10^{+20}$). Values obtained using the type curve procedure has no error associated; in contrast, one error of 1.29 % is obtained with the regression methodology.

Here, it is possible identify that damage by pressure changes and mechanical damage is estimated in 15 and 20 units, when type curve and regression procedures are applied, correspondently. Furthermore, one difference to one magnitude order is observe between results of C_D coefficient when are used both procedure. One possible explanation is related to fact the values of $C_De^{2s'}$ parameter are high number and that it depends of s' and C_D. Now, Darcy skin disaggregation procedure was applied. Results are presented in Table 5, where one value of 17 is obtained for both the mechanical and non-Darcy damages, however one small value of permeability's modulus is obtained, therefore, it is possible conclude that the well B drainage area is non-sensitive to pressure changes. Additionally, one acceptable value of matching of 0.27% is achieved.

However, using the equation (14), the skin by pressures changes is $s_p = 17\text{-}17$, i.e. s_p is null. On the other hand, Table 6 resumes the disaggregation skin on the Well B, likewise, the percentage value respect to total skin. Results to Table 6 indicate that mechanical skin is the predominant formation damage with a percentage of total skin factor equal to 85%, which implies that the well B could be stimulated using a conventional operation, like acidification, hydraulic fracturing, among others.

Conclusions

Main result of this work was the development of methodology to identify and quantify non-Darcy skin, as also allowed to obtain both the mechanical and geomechanical skin. There was an acceptable matching by using regression method, because there is a coincidence between both results (regression and type curves methodologies), giving an indicator of the validity of the model. Results showed the presence of non-Darcy skin in gas wells with high flow rates, this effect has been seen in the behavior of the type curves generated for each well in the study. Specifically, it shows the formation damage disaggregation importance, which allows identify and quantify the main component of damage, as well as make a decisions about the type of remediation of this damage. Finally, this procedure generates additional variables, such as: damages, wellbore storage coefficient, permeability modulus, which contribute to the characterization of reservoir, from both turbulent flow and geomechanical behaviors.

Acknowledgment

The authors thank the Universidad Nacional de Colombia –Medellin campus for allowing this work.

Nomenclature

B	Formation volumetric factor
c_t	Total compressibility
C	Wellbore storage coefficient
D	Non-Darcy flow coefficient
h	Thickness
k	Darcy permeability
q_{sc}	Rate to standard conditions
q_{sf}	Sandface rate
p	Pressure
p_{sf}	Sandface pressure
p_w	Sandface flow rate
r	Radius
s	Pressure changes skin and mechanical skin
s'	Total skin factor

s_m Mechanical skin factor
s_p Skin by pressure changes
t Time
v Velocity
α_{ND} Non-Darcy parameter
β Non-Darcy permeability tensor
γ Permeability modulus
ϕ Porosity
Φ Flow potential
μ Viscosity

Subscripts

D Dimensionless
i Initial condition
w Well

Conversion factors SI

cp x 1.0*	E -03	=	Pa.s
ft x 3.048*	E -01	=	m
Darcy x 9.869233	E -13	=	m^2
psi x 6.894757	E+03	=	kPa

*Exact conversion factor.

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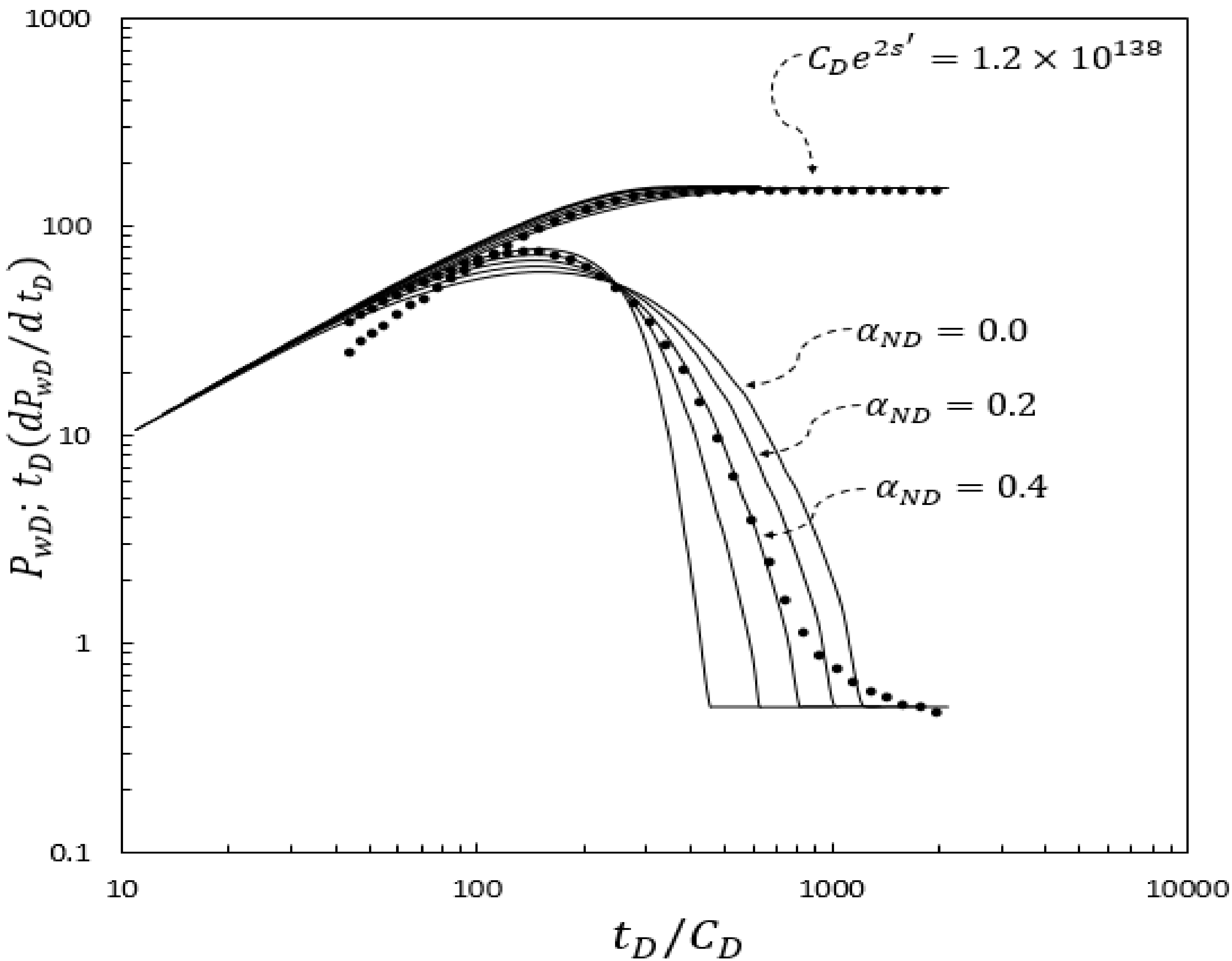

Figure 1. Matching of both actual and simulated using Spivey's type curves analysis on the Well A.

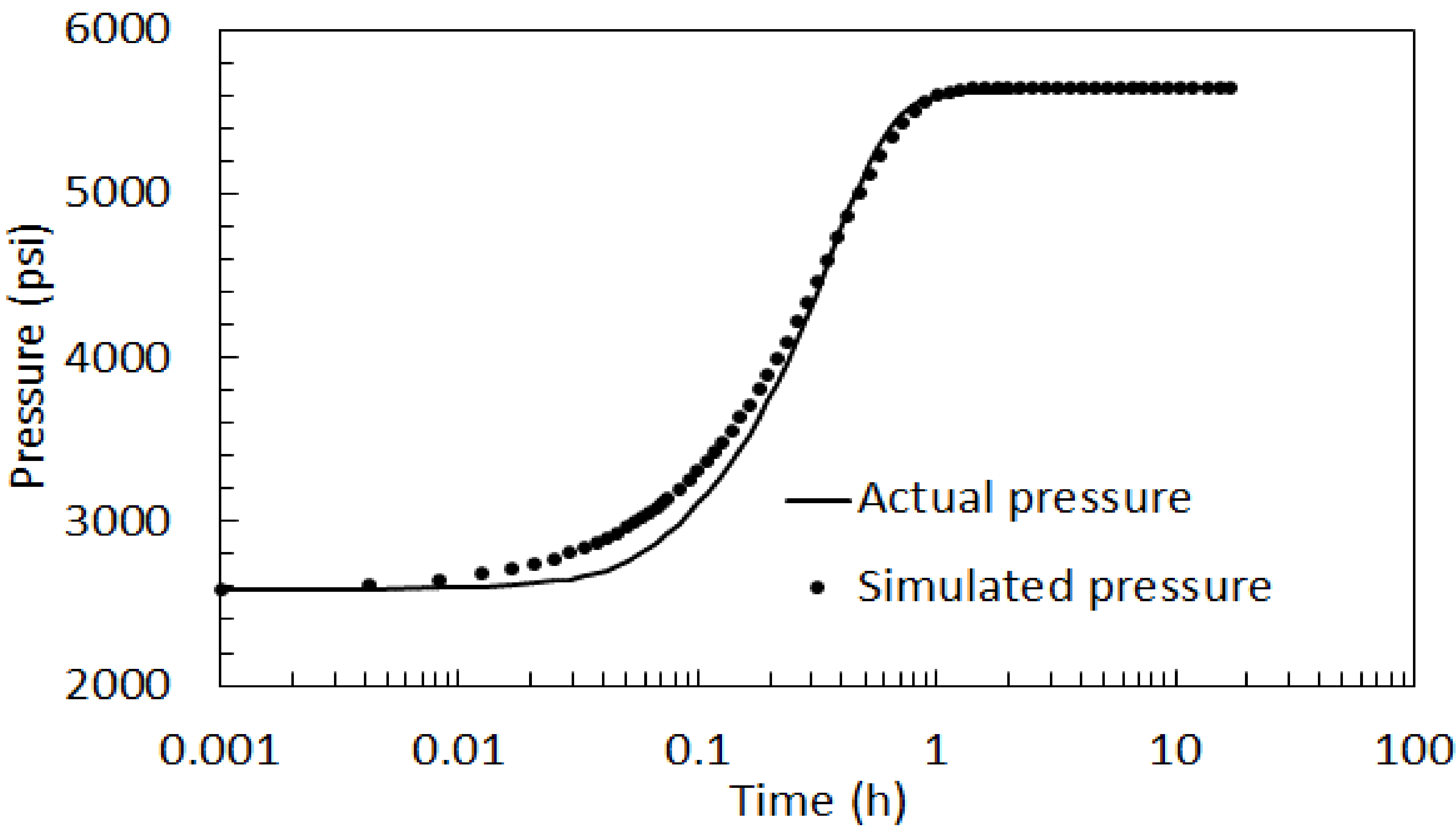

Figure 2. Matching of both actual and simulated pressure, when Spivey's regression procedure is applied on the Well A.

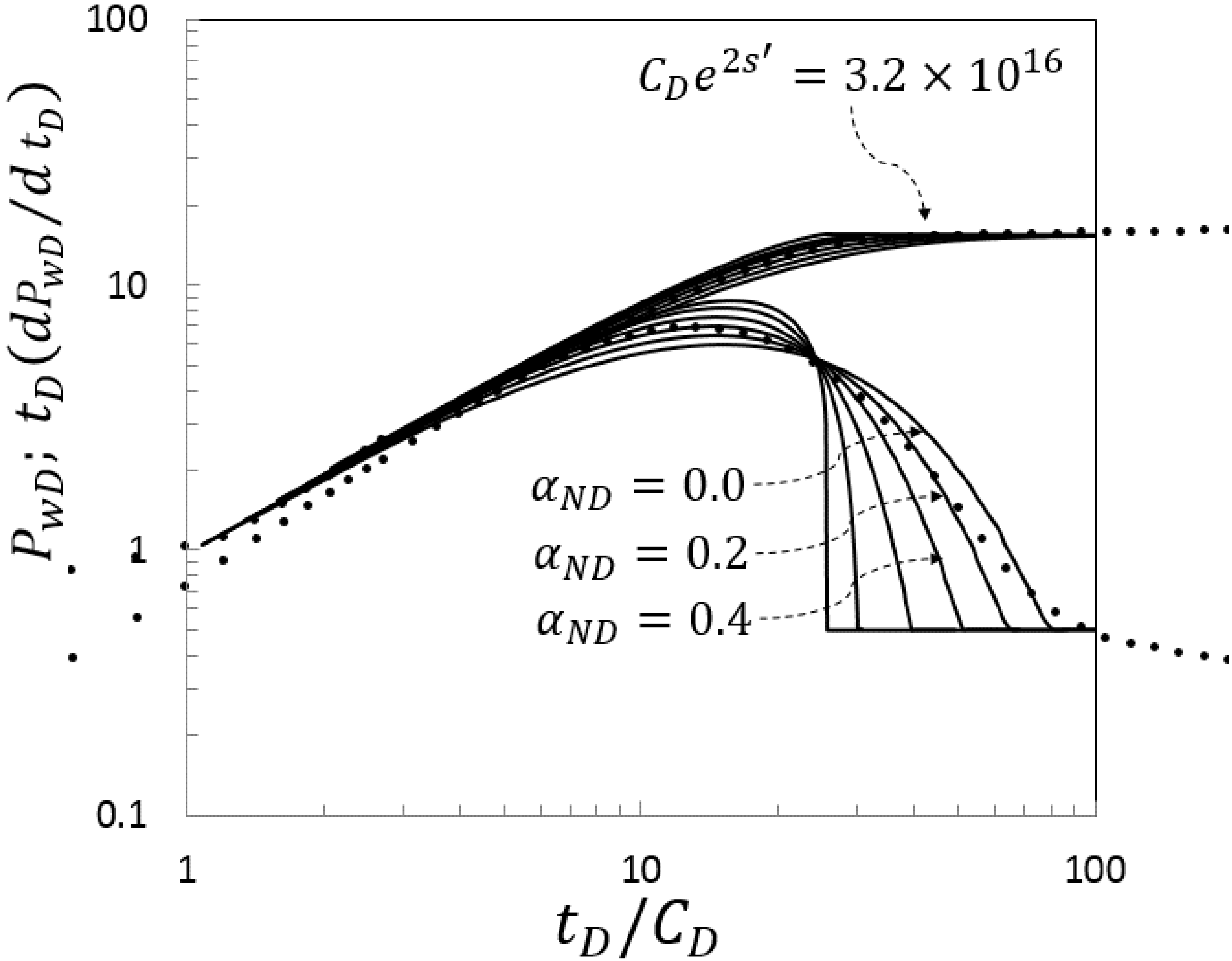

Figure 3. Matching of both actual and simulated using Spivey's type curves analysis on the Well B.

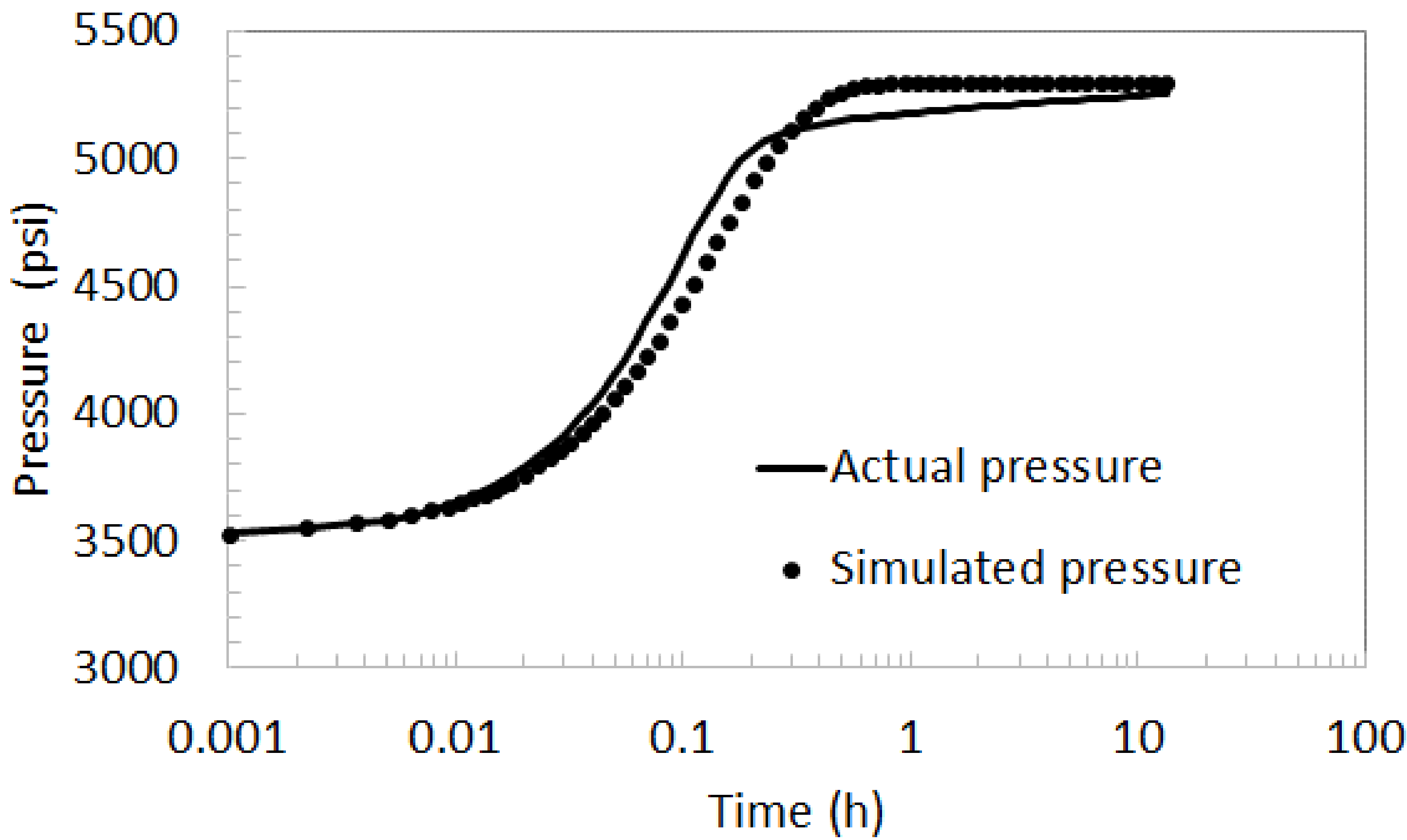

Figure 4. Matching of both actual and simulated pressure, when Spivey's regression procedure is applied on the Well B.

Parameter	*Type curve*	*Regression*
α_{ND}	0.4	0.52
$C_D e^{2s'}$	$1.23\text{x}10^{+138}$	$6.44\text{x}10^{+132}$
Error %	-	0.30
Other variables		
C_D	14575	1450
s'	154	149
D	$3.93\text{x}10^{-03}$	$4.94\text{x}10^{-03}$
s	91	69
D_D	63.59	80

Table 1. Results of application to Spivey's methodology using type curve and regression procedure on the Well A.

Parameter	*Regression ATS*
s	69
γ (1/Psi)	1.29×10^{-3}
s_m	30
C_D	2000
Error %	0.2

Table 2. Results obtained applying ATS on the well A.

Damage factor	*Value*	*Percentage*
s'	149	-
s_m	30	20%
s_p	39	26%
$D_D = Dq_{sc}$	80	54%

Table 3. Disaggregation skin summary - Well A.

Parameter	*Type curve*	*Regression*
α_{ND}	0.2	0.13
$C_D e^{2s'}$	$3.17\text{x}10^{+16}$	$1.54\text{x}10^{+20}$
Error %	-	1.29
Other variables		
C_D	1805	500
s'	15	20
D	$8.35\text{x}10^{-6}$	$5.60\text{x}10^{-5}$
s	11	17
D_D	3.8	3.0

Table 4. Results of application to Spivey's methodology using type curve and regression procedure on the Well B.

Parameter	*Regression ATS*
s	17
γ (1/Psi)	$1.34x10^{-8}$
s_m	17
C_D	1700
Error %	0.27

Table 5. Results obtained applying ATS on the Well B.

Damage factor	*Value*	*Percentage*
s'	20	-
s_m	17	85%
s_p	0	0%
$D_D = Dq_{sc}$	3	15%

Table 6. Disaggregation skin summary - Well B.