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Modelling scale saturation around the wellbore for non-Darcy radial flow system



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ABSTRACT

Scaling is a major profit hurting and aching occurrence induced by extensive use of seawater for oil displacement and pressure maintenance; hence it consequently results in production losses and loss of billions of dollars to the petroleum industry yearly. Over the years several models have been developed for predicting the effect of different variables such as pressure, temperature, ions, and pH on the behaviour of mixture of incompatible waters, scaling tendency, amount of scale precipitates which did not account for the quantity deposited around the wellbore. Few research works have been done to show the effect of reservoir and fluid parameter on the magnitude of scale deposition around the wellbore. The most recent formulations for predicting sulphate scale saturation around the wellbore assuming Darcy flow condition was developed and applied to real life scenario by experts in Colombia field. However, flow through a narrow channels often use in describing permeability loss modelling because pore throat and pore spaces become narrower and tighter during scale particle deposition and blockage around the well bore. Then high fluid velocity experiences when it is moving through narrow and tighter channels hence, results in non-Darcy flow that is always experience at the near wellbore region.

This paper presents analytical model for predicting sulphate scale saturation near the wellbore under the non-Darcy flow condition. The results obtained show that the previous models under estimated scale saturation at the near well bore region.

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1. Introduction

Oilfield scale has been defined to be inorganic crystalline substances that can be formed at any point or stage during the extraction of oil and gas, once the formation water is affected by supersaturation with respect to some solute either by being subjected to thermodynamic conditions of temperature and pressure for scale formation or by the reaction between incompatible waters [1]. Scale deposition in petroleum reservoir during water injection technique is one of the most serious problems affecting the oil and gas industry because of its immense effect on productivity [2–3], if left untreated. It reduces the productivity of the well by blocking the flow paths of the oil and gas into the well bore from the reservoir [4–5].

Barium Sulphate scale is among the most common of the different inorganic Sulphate salts precipitating from reservoir brines. Barium Sulphate scale can cause loss of permeability around the wellbore area, accrue inside of the flowing lines, and plug valves

and other facilities [6–8]. The occurrence leads to reduction in well productivity. On like other types of mineral scale, the treatment and removal of Barium Sulphate scale is not easily achieved [3], since it is only slightly soluble in acids.

Various solubility models suitable for predicting and approaching the problem of Barium Sulphate minerals scaling naturally obtained in the oil and gas formation have been developed. Most of these accessible formulations for prediction of scale were developed based on limited solubility and thermodynamics information. Hence they can only estimate the scaling tendency, thereby rendering the capacity to estimate scale precipitation which is a challenging issue in the oil and gas field operation [8,9].

Amiri and Moghadashi [10] described the use of SCALECHEM algorithm to predict the amount of barium sulphate that formed under existing thermodynamic conditions. The model used in the software calculated scaling potential and precipitates. A predictive tool that is capable to estimate potential of common oil field scale in water disposal wells, water flooding systems and in surface equipment and facilities was developed [5,9]. Fadairo et al. [11] reported new thermodynamic based models for predicting sulphate scales saturation and their corresponding loss of permeability near the

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Nomenclature

B	formation volume factor, dimensionless	R	gas constant ($83.15 \text{ cm}^{-3} \text{ K}^{-1} \text{ mol}^{-1}$)
C	amount of scale, m^3/m^3	δS	sulphate scale saturation, dimensionless
$C(I)$	concentration at wellbore pressure, g/m^2	S_w	irreducible water saturation, dimensionless
$C(P)$	concentration at reservoir pressure, g/m^2	$\frac{\partial S}{\partial t}$	scale build-up rate, ratio/s
h	reservoir thickness, m	$S.I$	saturation index, dimensionless
I	ionic strength of the saturated solution, M	t	production time, s
K	instantaneous permeability, m^2	T	reservoir temperature, K
K_o	original permeability, m^2	V	mineral scale volume, m^3
K_{dep}	deposition rate constant	V^O	molar volume change per mol of salt dissolved
K_{sp}	solubility product M^2	ϕ	instantaneous porosity, dimensionless
K^O	molar compressibility change per mol of salt dissolved	ϕ_o	original porosity, dimensionless
P	pressure, Pa	ρ	density, g/m^3
q	flow rate, m^3/s	μ	viscosity of fluid, pa-s
r	radial distance, m		

well during water flooding while considering fraction of scales occupying pore spaces under Darcy flow condition. The field application of models was presented by Carmen et al. and Franco et al. [12,13] and has shown perfect agreement with the field results. Frank and Civan [14] suggested that flow through a narrow channels often use in modelling permeability loss induced by scale deposition should be non-Darcy flow because pore throat and pore spaces become narrower and tighter during scale particle deposition and blockage around the well bore. Then high fluid velocity experiences when it is moving through narrow and tighter channels. Therefore the steady flow assumption which describes the linear relationship between the velocity and pressure drop may not longer holds for real flow scenario. Non-Darcy flow is always experience at the near wellbore region which pose additional pressure drop due to turbulence which was overlooked in the previous investigation. Hence, there is the need to develop more realistic model for predicting oilfield scale saturation around the well bore where high fluid velocity is experienced.

This paper presents analytical model for predicting sulphate scale saturation near the wellbore under the non-Darcy flow condition. The newly developed model is useful for operators to refine their procedures and better manage the risk of flow assurance problems induced by barite scale during water flooding.

2. Model development

2.1. Scale saturation model for non-Darcy flow in radial flow system

Consider the radial flow of a fluid saturated with solid particles at constant rate q , and location r from the wellbore. Assuming non-Darcy flow conditions, Forchheimer [15] developed an equation of flow that considers the additional pressure decline due to unsteadiness, which is;

$$\frac{dp}{dr} = \frac{\mu}{k} u + \beta \rho u^2. \quad (1)$$

$$\text{Let } u = \frac{qB}{2\pi rh}. \quad (2)$$

Substituting Eq. (2) into 1 and assuming an exponential formation damage function as reported in the earlier works [1,7,14], Eq. (1) can be written as

$$\frac{dP}{dr} = \frac{qB\mu \exp(3K_{dep}Ct)}{2\pi rhK} + \frac{\beta \rho q^2 B}{4\pi^2 r^2 h^2} \quad (3)$$

The alteration in the scale volume δV_s which precipitates out and is accumulated in the elemental volume across the time interval, δt is reported as follows: Robert [16]; ($\delta V =$ time interval * flow rate).

$$dV = q \cdot \left(\frac{dc}{dp} \right) \cdot dp \cdot dt. \quad (4)$$

where $\frac{dc}{dp}$ is the change in saturated solid mineral particle per unit pressure alteration.

The saturation change of scale deposited throughout this time interval can be defined as

$$\delta S = \frac{\text{Volume of scale deposition}}{\text{Volume of the whole spaces}} \quad (5)$$

Instantaneous porosity was given an expression by Frank and Civan [14] as:

$$\phi = \phi_o \text{Exp}(-k_{dep}C \cdot t) \quad (6)$$

Hence, over time interval dt , the change in the saturation of scale deposition can expressed as

$$dS = \frac{V_s}{V_p} = \frac{q \left[\frac{dc}{dp} \right]_T dP dt}{2\pi dr h \phi_o \text{Exp}(-k_{dep} \cdot C \cdot t) (1 - S_w)} \quad (7)$$

Substituting Eq. (3) into (6) and evaluate, we have

$$dS = \frac{q^2 B \mu \left(\frac{dc}{dp} \right)_T \exp(4K_{dep}Ct) dt}{4\pi^2 r^2 h^2 K_o \phi_o (1 - S_{wi})} + \frac{\beta \rho q^3 B \left(\frac{dc}{dp} \right)_T \exp(K_{dep}Ct) dt}{8\pi^3 r^3 h^3 \phi_o (1 - S_{wi})} \quad (8)$$

Incorporating instantaneous porosity and permeability into the Eq. (8); and evaluating, we have

$$dS = \frac{0.02532 q^2 \cdot \left[\frac{dc}{dp} \right]_T \cdot B \cdot dt \cdot \exp(k_{dep} \cdot C \cdot t)}{r^2 h^2 \phi_o (1 - S_w)} \times \left(\frac{\mu \exp(3K_{dep}C \cdot t)}{K_o} + \frac{2.158 \times 10^{-6} q \cdot \beta \cdot \rho}{rh} \right) \quad (9)$$

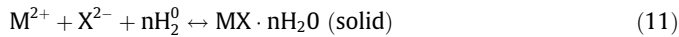
Thermodynamic model for each salt involved can be used to determine $\left[\frac{dc}{dp} \right]$ by following the procedures in the literature [17–18]. The outcome obtained for the salt's concentration and saturation index depends on temperature, pressure and ionic strength.

The expression for the saturation index (S.I) is given by: [11,18,19]

$$S.I = \log[\text{Me}][\text{An}] + pK_{sp} \quad (10)$$

The concentration of salts precipitated in mass per volume is the amount of solid salts precipitated from an oversaturated

mixture when the equilibrium state is reached [4,18–24]. When a divalent cation M^{2+} and anion X^{2-} reacts, a solid phase MX is formed which precipitates out or dissolved in solution according to the following equation [20–24]:



The original amount of precipitation got is utilized as the initial average concentration of precipitated minerals in the reservoir [18]. The relationship between the original mean concentration of scale at reservoir pressure and mean concentration at well bore bottom-hole pressure can be thermodynamically expressed as [20]:

$$\frac{C(P)}{C(I)} = EXP\left(\frac{-\Delta V^0 \Delta P}{RT} + \frac{\Delta K^0 (\Delta P)^2}{2RT}\right) \quad (12)$$

Therefore, the concentration change per unit pressure gradient for scales can be expressed [9] as:

$$\left(\frac{dC}{dP}\right) = \frac{C(P) - C(I)}{\rho \Delta P} \quad (13)$$

3. Discussion of results

The effects of additional pressure drop induced by the turbulent factor on the barite scale deposition around the wellbore have been estimated and analyzed using the data of the Oilfield presented by Haarberg et al. [17] in their paper. The chemical ions concentration for formation and seawater, the amount of scale precipitates at different pore volume and the base reservoir and fluid parameter were presented as Tables 1–3 respectively;

$BaSO_4$ salt at different proportions obtained from the mixture of the chemical composition of the sea water and formation water in Table 2

Fig. 1 shows a plot of saturation against pore volume at a radial distance of 0.5 m using both the Fadaïro et al. [9] model (Darcy) and the new model (non-Darcy). It is noticed that there is a corresponding high disparity between the saturation values gotten from the Fadaïro et al. [9] model (Darcy) and the new model (non-Darcy). The maximum saturation value gotten at 10% pore volume for Fadaïro's Model, 0.1057 is lesser than that of the new model which is 0.2260. The higher saturation values gotten from the new model is as a result of the additional pressure drop due to turbulence at the near-wellbore region.

Fig. 2 shows a plot of saturation against pore volume at a radial distance of 1 m using both the Fadaïro et al. [9] model (Darcy) and the new model (non-Darcy). The maximum saturation values generated from both models at 1 m radial distance compared to the ones gotten from Fig. 1 at radial distance of 0.5 m decreases because farther away from the wellbore the effects of turbulence

Table 1
Sea water and formation water chemical composition.

Ion	Sea water	Formation water
pH	8.13	6.20
Na ⁺	12465 (mg/l)	14859 (mg/l)
K ⁺	–	–
Mg ²⁺	1130 (mg/l)	335 (mg/l)
Ca ²⁺	450 (mg/l)	1275 (mg/l)
Si ²⁺	9 (mg/l)	335 (mg/l)
Ba ²⁺	–	50
Cl ⁻	20950 (mg/l)	26,200 (mg/l)
SO ₄ ²⁻	3077 (mg/l)	–
HCO ⁻³	170 (mg/l)	415 (mg/l)

Table 2
Amount of $BaSO_4$ precipitates formed against the percentage of sea water injected.

Pore volume injected (%)	$BaSO_4$ precipitate g/m ³
0	0.0
10	71.0
20	65.0
30	58.0
40	48.0
50	42.0
60	32.0
70	25.0
80	18.0
90	10.0
100	0.0

Table 3
Properties of fluid and reservoir used as input in this work after Robert Bruce [16]

Reservoir and fluid parameters	Values
Reservoir thickness (h)	26 m
Original permeability	0.5922E–13 m ² (60 mD)
Original porosity	0.04
Reservoir pressure	36600 kpa
Bottom hole pressure	22060 kpa
Reservoir temperature	353 K (80 °C)
Viscosity of water	0.0007 Pa-s
Irreducible water saturation	0.2
Formation volume factor	0.254

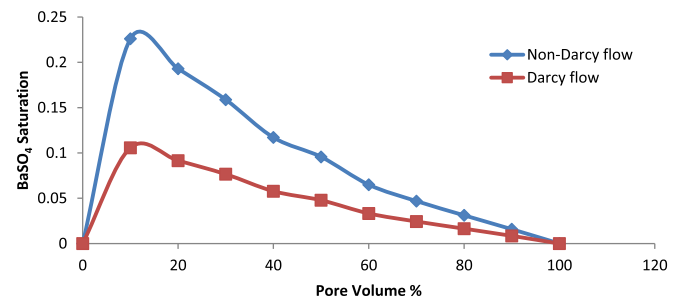


Fig. 1. Saturation of $BaSO_4$ against pore volume at 0.5 m radial distance from the well using the Fadaïro et al. [9] model and the new model.

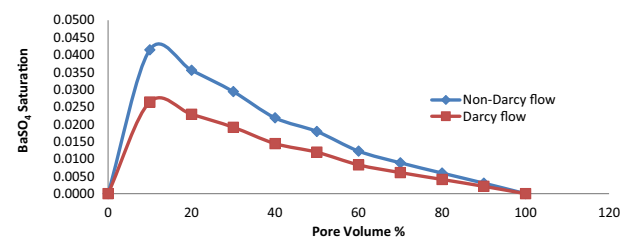


Fig. 2. Saturation of $BaSO_4$ against pore volume at 1.0 m radial distance from the well using the Darcy Fadaïro et al. [9] model and the new model.

greatly reduces often causing it to be neglected in some flow equations. This also infers that scaling problem is a near-wellbore problem [21].

Figs. 3–5 show the plot of saturation against time at pore volume of 60% at radial distances of 0.1 m, 1.0 m and 2.0 m away from the wellbore respectively. It is noticed that the highest values of saturation are recorded at the location closer to the wellbore and reduces as the location farther away from the wellbore because the effect of turbulence is greatly diminished. The effect of turbulence would continue to reduce until the Fadaïro et al. [9] model

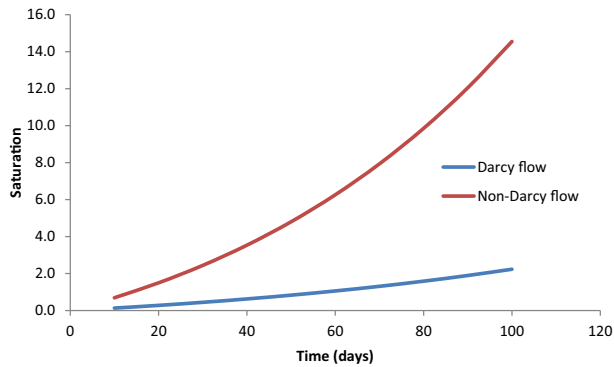


Fig. 3. Saturation of BaSO_4 against time at 0.1 m radial distance from the well using the Darcy based model and the non-Darcy based model.

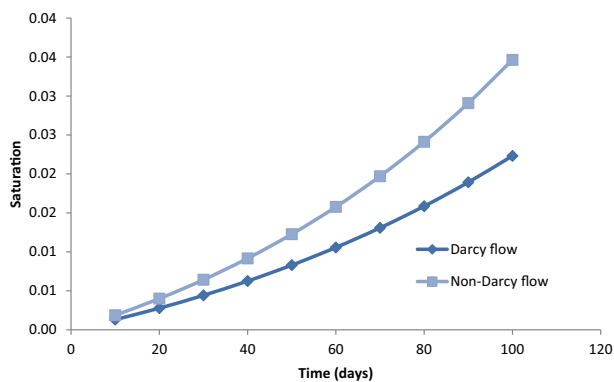


Fig. 4. Saturation of BaSO_4 against time at 1.0 m radial distance from the well using the Darcy based model and the non-Darcy based model.

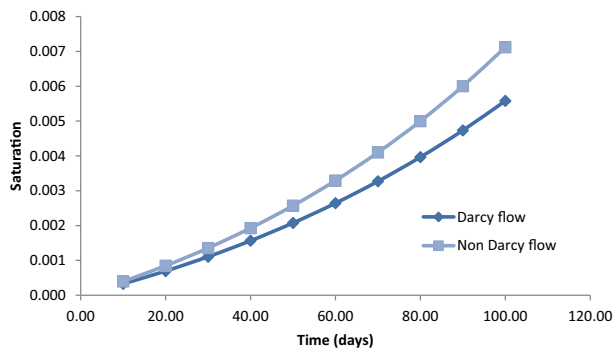


Fig. 5. Saturation of BaSO_4 against time at 2.0 m radial distance from the well using the Darcy based model and the non-Darcy based model.

prevails as the non-Darcy part of the pressure drop equation approaches zero.

Fig. 6 is a plot of saturation against time at different radial distances of 0.1 m, 0.5 m, 2.0 m and 5.0 m for both Darcy and non-Darcy flow conditions. As the radial distance increases away from the wellbore the effects of turbulence gradually decreases hence evident that the effect of turbulent on scale deposition, occurring generally after some period of production time with the huge induced formation damage noticed at the non-Darcy flow condition. This indicated that higher deposits of scale occurs at a region where non-idealized flow (non Darcy flow) condition is experienced compared with the region where idealized flow (Darcy flow condition) is experienced [21].

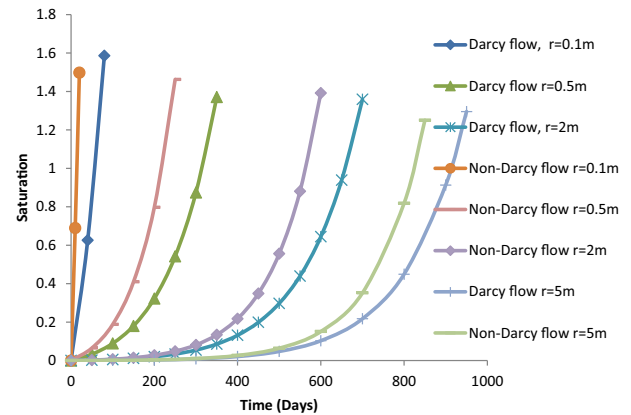


Fig. 6. BaSO_4 saturation against time at different locations away from the wellbore under Darcy flow and non-Darcy flow conditions.

4. Conclusion

The presented model predicts the rate at which sulphates scale are deposited for a given rate of water injected and at a particular time and location around the wellbore in the reservoir.

It also reveals the effects of changes in pressure and temperature on Barium sulphate scale deposition as the injection water flow from reservoir to the production well.

The rate at which scale builds up around the wellbore may show significant reduction by declining the pressure gradient near the wellbore at a given water injection rate is also determined by the model, therefore decreasing the rate at which water is injected will reduce the rate at which scale is formed around the well.

The addition of the non-Darcy component causes an additional pressure drop which leads to additional scale deposition.

The effect of turbulence on scale deposition in the direction towards the wellbore and is less pronounced as we move away from the wellbore.

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