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Modified Model for Predicting Permeability Reduction Due To Scale in a Porous Media

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ABSTRACT

Scale and precipitate is the result of the reaction of fluid and the physical environment which is generally not desirable in porous media. The mineral deposit formed is due to fluid and fluid; Rock and fluid interaction which leads to Super-saturation and precipitation.

This process that causes scale deposition leads to alteration in the permeability of sediments which could be through the plugging of pore throats as well as solid deposition in the reservoir rock pores.

Research works by different authors has been done in the past to investigate the deposition of scale in porous media, effect of brine on the ion concentration and also the permeability reduction due to scale based on Darcy flow.

This work however takes a different approach by considering the permeability reduction as a result of non-Darcy flow because of the high velocity of fluid that would occur at the tight pore spaces and throat. The work was done by integrating the non-Darcy saturation of scale model into the expression of permeability ratio as a function of damaged or altered porosity.

The result of the model was validated with the actual data gotten from Well A of Putumayo area in Colombia. The model can be used to predict the non-Darcy reduction in permeability as a result of scale near the wellbore.

I. INTRODUCTION

Saline solution contained in fluid flowing through a porous media results into a complex problem because of the mineral scales formed as a result of reaction between the fluid and the physical environment. The result of the reaction of fluid and the physical environment forms precipitates and scales which is generally not desirable in porous media. For example, scaling is an ordinary and a common challenge in several areas such as production industries of oil and gas, membrane separation processes and geothermal energy production (Bennion, 2001).

The main consequence from scales is that it constricts flow of fluid and in the worst case scenario it can cause total blockage. This process essentially leads to alteration (changes) in the permeability of sediments which could be through the plugging of pore throats as well as solid deposition in the reservoir rock pores.

The mineral deposit formed can be because of fluid and fluid; Rock and fluid interaction which leads to Super-saturation and precipitation following after (Olkeksandr P.Ivakhnenko et al). Many scales are not soluble in acid and as a result are difficult to remove, examples are Gypsum and Anhydrite.

The hydrated form of Anhydrite is the most common of the scale types, most often called gypsum or Calcium sulfate. Mixing of brines that contain different concentrations of calcium and sulfate ions may initiate scaling (Atkinson and Mecik, 1997).

Prediction of sulfate scale based on extended UNIQUAC model was proposed by Villafafia et al. (2005) whileShen et al. (1970), probed into mechanism in charge of Calcium sulfate scale formation in wells producing oil. The literature work shows the complexity of anticipating scale formation.

Mackay(2005) did develop a model with theoretical bases for studying deposition of scale because of the mixture of water injected, connate water, aquifer brines which is in water flooding and applying it to scaling in oilfield. The model showed the calculation for a range of sensitivities which includes the reservoir geometry, geometry of the well as well as the reaction rate.

Ahmed (2004) presented a theoretical and experimental work, the work showed studies on permeability reduction in Bearea sandstone core as a result of calcium sulfate deposition. The work

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also showed the temperature effect, the concentration and brine solution volume flow rate reacting constantly with $CaSO_4$.

The complexity of predicting the mineral deposit and reduction in permeability of porous media has been described in many literature. Predicting the formation of scale for injection and the well path of production with its porosity and reduction in permeability rate is expedient to successfully complete the operation.

Calcium sulfate is a major scale that severely impairs flow and causes damage to the formation.

Parameters like Temperature, Pressure, ions of concentration in solution injected,porous media surface properties, porosity at the initial stage and porous media permeability, the dynamic of fluid in the porous media, movement of particles in the pores and the throat paths, time of crystallization induction , injected fluid cumulative volume, mineral salts super saturation degree in solution injected, precipitation of mineral salt with common ion, mineral salt nucleation, bulk and surface crystallization, velocity effect of fluid on crystal form and crystallization, physical property variation of fluid as a result of crystallization and crystal precipitation, precipitation reaction rate and growth rate of crystal, distribution of throat size and pore, distribution of crystal size, adsorption of multi component in the pore and throat surface, convection and diffusion transfer of mass are parameters described by different authors to be affected by scaling (Ahmed, 2004; Firas et al., 2005; Hennessy and Graham, 2002; Tahmasebi et al., 2007; VillafafiaGarica et al, 2005).

MODEL DEVELOPMENT

ASSUMPTIONS:

The following assumptions were made;

- Non-Darcy flow condition
- There is uniform suspension of the solid precipitates in an incompressible fluid
- It is an homogeneous isotropic and isothermal porous medium
- There is negligible forces of interaction between the precipitated solid minerals and the medium.
- There is a large number of pore space in the porous media and it is interconnected by log-normally distributed size of pore throat.

Instantaneous porosity is the difference between initial porosity and pore spaces fraction that is damaged. Fadairo (2009).

$\varphi_s = \varphi_o - \varphi_d$ (1)

$\varphi_d = \frac{\text{Volume of minerals scale deposited}}{\text{bulk volume of the porous media}}$ (2)

dv which is the volume of scale that is deposited in a volume of element across time, dt was given by: (Robert, 1997; Civan,2001)

$dv = q * \left[\frac{dC}{\rho dP}\right]_T * dP * dt$ (3)

Therefore change in deposited porosity over a time interval is;

$d\varphi_d = \frac{q * \left(\frac{dC}{dP}\right)_T * dp * dt}{2 * \pi * rs * dr * h * \rho}$ (4)

Where $\left(\frac{dC}{dP}\right)_T$ is termed ratio of change of solid saturated scale to change in pressure, with temperature being constant.

Fadairo(2004) assumed an ideal flow condition and expressed pressure gradient as a result of scale presence as

$\frac{dp}{dr} = \frac{q * B * \pi * \exp(\beta * Kdep * C * t)}{2 * \pi * Ko * h * rs}$ (4a)

substituting equation 4a into equation 4 and integrating would give the damaged fraction of the pore space as;

$\varphi_d = \frac{q^2 * \left(\frac{dC}{dP}\right)_T * B * \mu * t * \exp(\beta * Kdep * C * t)}{12 * \pi^2 * rs^2 * h^2 * Ko * \rho}$ (5)

Substituting equation 5 in equation 1 would give;

$\varphi_s = \varphi_o - \frac{q^2 * \left(\frac{dC}{dP}\right)_T * B * \mu * t * \exp(\beta * Kdep * C * t)}{12 * \pi^2 * rs^2 * h^2 * Ko * \rho}$ (6)

Fadairo (2017) expressed the non-Darcy fraction of scale that occupies pores spaces with consideration of different radial distances.

$$ds = \frac{0.02532*(q^2)*\mu*\left(\frac{dc}{dp}\right)*B*exp\,(4Kdep*C*t)dt}{r^2*h^2*\emptyset o*Ko*(1-swi)} + \frac{5.464*10^{-8}*q^3*\beta*\left(\frac{dc}{dp}\right)*B*\rho*dt*exp(Kdep*C*t)}{r^3*h^3*\phi o*(1-swi)} \quad (7)$$

Integrating the equation with respect to time gives;

$$S = \frac{0.02532*(q^2)*\mu*\left(\frac{dc}{dp}\right)*B*exp\,(4Kdep*C*t)}{4*r^2*h^2*\emptyset o*Ko*(1-swi)} + \frac{5.464*10^{-8}*q^3*\beta*\left(\frac{dc}{dp}\right)*B*\rho*exp(Kdep*C*t)}{r^3*h^3*\phi o*(1-swi)} \quad (8)$$

$$S = \frac{(q^2)*\left(\frac{dc}{dp}\right)*B*exp\,(Kdep*C*t)*t}{r^2*h^2*\emptyset o*(1-swi)*t} * \left[\frac{(6.33*10^{-3})*\mu*exp\,(3Kdep*C*t)*}{Ko} + \frac{(5.464*10^{-8})*q*\beta*\rho}{r*h}\right] \quad (9)$$

Where;

$$\lambda_k = exp(3K_{dep}*C*t) \quad (10)$$

$$\lambda_\varphi = exp(-K_{dep}*C*t) \quad (11)$$

Rearranging equation 9 gives;

$$\frac{S*r^2*\varphi o*(1-swi)*\lambda\varphi*t}{\left[\left(\frac{(6.33*10^{-3})*\mu*\lambda k}{Ko}\right)+\left(\frac{(5.464*10^{-8})*q*\beta*\rho}{r*h}\right)\right]} = \frac{q^2*\left(\frac{dC}{dP}\right)_T*B*t}{h^2} \quad (12)$$

Rearranging equation 6 gives

$$\varphi_s = \varphi_o - \left[\frac{q^2*\left(\frac{dC}{dP}\right)_T*B*t}{h^2} * \frac{\mu*\lambda k}{12*\pi^2*r_s^2*K_o*\rho}\right] \quad (13)$$

Substitute equation 12 in equation 13

$$\varphi_s = \varphi_o - \left[\frac{S*r^2*\varphi o*(1-swi)*\lambda\varphi*t}{\left[\left(\frac{(6.33*10^{-3})*\mu*\lambda k}{Ko}\right)+\left(\frac{(5.464*10^{-8})*q*\beta*\rho}{r*h}\right)\right]} * \frac{\mu*\lambda_K}{12*\pi^2*r_s^2*Ko*\rho}\right] \quad (14)$$

Dividing both sides by initial porosity would give the formula for porosity ratio, given as;

$$\frac{\varphi s}{\varphi o} = 1 - \frac{Ss*(1-Swi)*\lambda\varphi*\lambda k*\mu*t}{12*\pi^2*Ko*\rho\left[\frac{(6.33*10^{-3})*\mu*\lambda k}{Ko}+\frac{(5.464*10^{-8})*q*\beta*\rho}{r*h}\right]} \quad (15)$$

The relationship between permeability ratio and altered porosity given by, (Civan et al, 1989; Frank et al, 1991) is

$$\frac{Ks}{Ko} = \left(\frac{\varphi s}{\varphi o}\right)^3 \quad (16)$$

Substitution equation 15 into equation 16 gives the modified model for calculating permeability ratio under non-Darcy flow.

$$\frac{Ks}{Ko} = \left[1 - \frac{S*(1-Swi)*\lambda_\varphi*\lambda_K*r^2*\mu*t}{12*\pi^2*r_s^2*Ko*\rho\left[\frac{(6.33*10^{-3})*\mu*\lambda k}{Ko}+\frac{(5.464*10^{-8})*q*\beta*\rho}{r*h}\right]}\right]^3 \quad (17)$$

The formula for skin factor is given as;

$$skin = \left(\frac{K_o}{K_s} - 1\right)\ln\frac{r_s}{r_w} \quad (18)$$

substituting equation 17 in equation 18 would give skin factor as a result of scale under non-Darcy flow

skin =

$$\left(\left[1 - \frac{S*(1-Swi)*\lambda_\varphi*\lambda_K*r^2*\mu*t}{12*\pi^2*r_s^2*Ko*\rho\left[\frac{(6.33*10^{-3})*\mu*\lambda k}{Ko}+\frac{(5.464*10^{-8})*q*\beta*\rho}{r*h}\right]}\right]^{-3} - 1\right)\ln\frac{r_s}{r_w} \quad (19)$$

International Journal of Advances in Engineering and Management (IJAEM)
Volume 7, Issue 07 July 2025, pp: 640-648 www.ijaem.net ISSN: 2395-5252

The pressure drop across the skin area is given as;

$$\Delta P_s = \frac{q * B * \mu}{2 * \pi * K_o * \left[1 - \frac{S * (1-Swi) * \lambda_\varphi * \lambda_K * r^2 * \mu * t}{12 * \pi^2 * r_s^2 * Ko * \rho\left[\frac{(6.33*10^{-3}) * \mu * \lambda k}{Ko} + \frac{(5.464*10^{-8}) * q * \beta * \rho}{r * h}\right]}\right]^3} \ln\frac{r_s}{r_w} - \frac{q * B * \mu}{2 * \pi * h * K_o} \ln\frac{r}{r_w} \quad (20)$$

Rearranging equation 20 gives equation 21 for Pressure drop across skin area

$$\Delta P_s = \frac{q * B * \mu}{2 * \pi * h * K_o}\left\{\left[1 - \frac{S * (1-Swi) * \lambda_\varphi * \lambda_K * r^2 * \mu * t}{12 * \pi^2 * r_s^2 * Ko * \rho\left[\frac{(6.33*10^{-3}) * \mu * \lambda k}{Ko} + \frac{(5.464*10^{-8}) * q * \beta * \rho}{r * h}\right]}\right]^{-3} - 1\right\} \ln\frac{r_s}{r_w} \quad (21)$$

VALIDATION OF THE MODEL

The permeability, skin factor and pressure drop of the model due to scale by water flooding was calculated using Microsoft excel. The permeability values were compared to the actual values gotten from Well A of Putumayo area in Colombia, Carmen et al model(2015) and Fadairo et al model(2009).

The data of Carmen et al model (2015) on Well A fluid production by periods, reservoir physical data are given in the Tables 1-3 below.

Table-1. The fluid production in periods

Period	**T, days**	**q_w, BPD**	**Q_o,BPD**	**g_g. MSCF/D**
1	13	40	815	975
2	13	14	900	1050
3	26	9	925	1075
4	150	6	905	1100
5	100	8.6	970	1150
6	100	22	925	1075

Table-2 The data of the physical reservoir model

Input data	**Period-1**	**Period-2**	**Period-3**
$q_{w,}m^3/s$	7.36065 * 10-5	2.57623x10-5	1.65615x10-5
dc/dp calcite	6.21x10-7	7.39x10-7	4.90x10-6
dc/dp siderite	5.17x10-8	1.47775x10-7	1.53248x10-7
dc/dp barite	5.17x10-8	1.47775x10-7	1.53248x10-7
$M_{dep.}$ gr/d Calcite	5196.24	1819.55	1169.76
$M_{dep.}$ gr/d Siderite	329.96	115.51	74.28
$M_{dep.}$ gr/d Barite	8.28	2.93	1.88
$C_{calcite}$, gr/m^3	817.04096	817.4322	817.4673
$C_{siderite}$, gr/m^3	51.88258	51.89124	51.90596
C_{barite}, gr/m^3	1.3016112	1.31435	1.3154792
Input data	**Period-4**	**Period-5**	**Period-6**
$q_{w,}m^3/s$	1.1041x10-5	1.58254x10-5	4.04836x10-5
dc/dp calcite	1.66x10-6	3.13x10-6	1.25x10-6
dc/dp siderite	2.75847x10-7	6.0141x10-8	2.08975x10-8
dc/dp barite	2.75847x10-7	6.0141x10-8	8.359x10-8
Mdep. gr/d Calcite	779.68	1119.87	2865.42
$M_{dep.}$ gr/d Siderite	49.51	70.96	181.50
$M_{dep.}$ gr/d Barite	1.25	1.84	4.76
$C_{calcite}$, gr/m^3	817.29297	818.999	819.1819
$C_{siderite}$, gr/m^3	51.898	51.898585	51.8894
C_{barite}, gr/m^3	1.307555	1.343492	1.361586

International Journal of Advances in Engineering and Management (IJAEM)
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Table-3. Reservoir physical input data

Parameter	Value
B_w(bbl/STB)	1.049
μ_w (cp)	0.292
h (ft)	129
Φ (%)	10
K_o(md)	64.318
S_{wi}	0.32
r_w(ft)	0.25
ρ_{brine}(g/cm^3)	1.01
$\rho_{calcite}$(g/cm3)	2.71
$\rho_{siderite}$(g/cm3)	3.96
ρ_{barite}(g/cm3)	4.5

II. DISCUSSION OF RESULTS

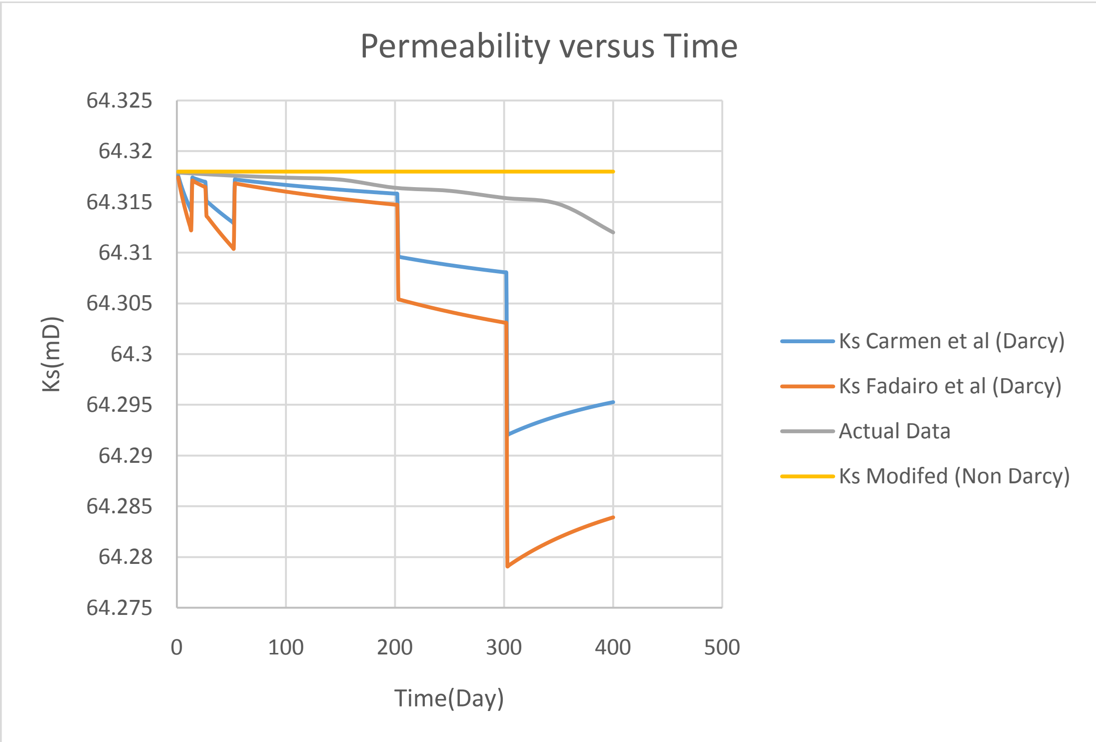

Figure 1. Comparison of permeability reduction

International Journal of Advances in Engineering and Management (IJAEM)
Volume 7, Issue 07 July 2025, pp: 640-648 www.ijaem.net ISSN: 2395-5252

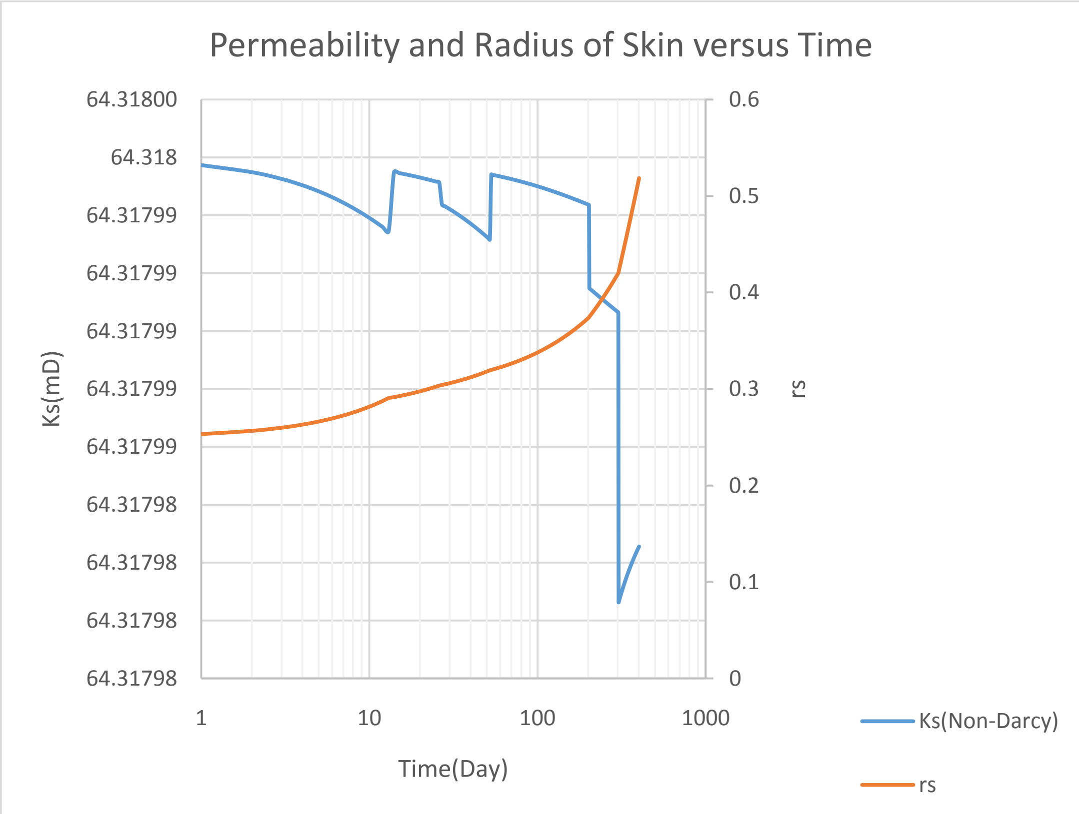

Figure 2.radial extent of damage and effect on permeability

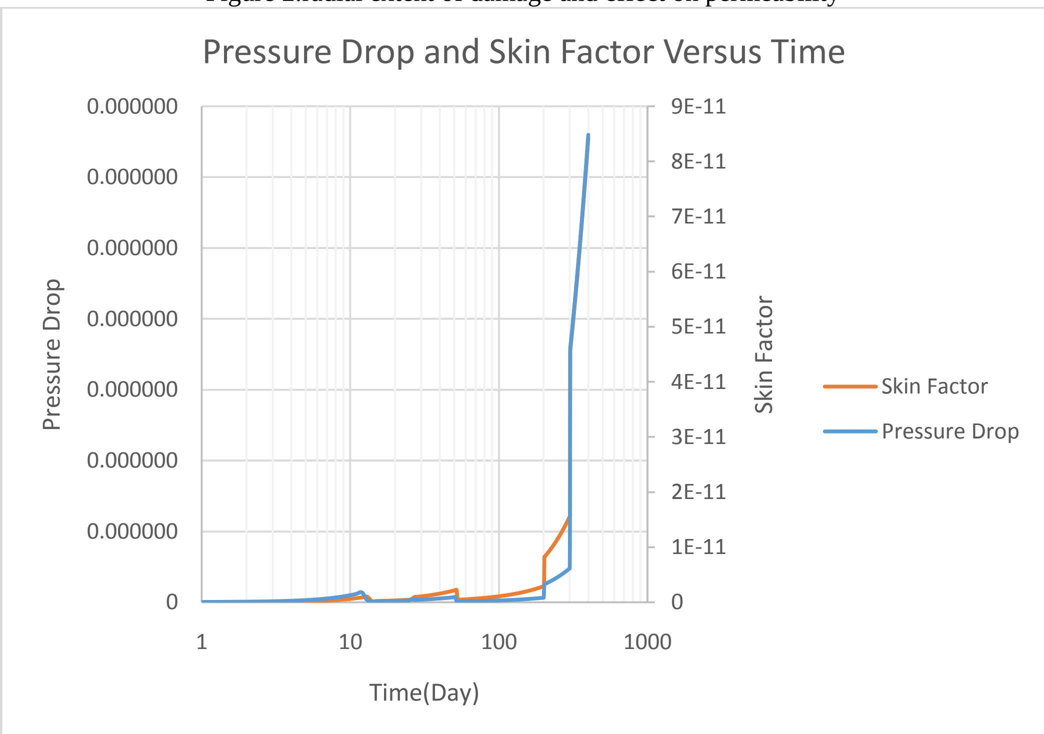

Figure3. Plot of Pressure Drop and Skin Factor which was caused by scale

Figures 1 to 3 shows reduction in permeability, radial extent of damage, skin and drop in pressure as a result of scale. A comparison was carried out in the plot of figure 1 which was

International Journal of Advances in Engineering and Management (IJAEM)
Volume 7, Issue 07 July 2025, pp: 640-648 www.ijaem.net ISSN: 2395-5252

taken from the study done by Carmen et al (2015).As obtained from figure 1 at time of 400 days the permeability of the modified model is closer to the actual data than the other models. The figure shows the modified model is 0.0059md higher than the actual data. In Figures 2 the plot shows as the radius of skin was increasing the permeability was decreasing and this is because of the damage of scale. Figure 3 shows the skin factor had equal effect on the pressure drop. The plot shows skin factor and pressure drop increases with increasing number of day.

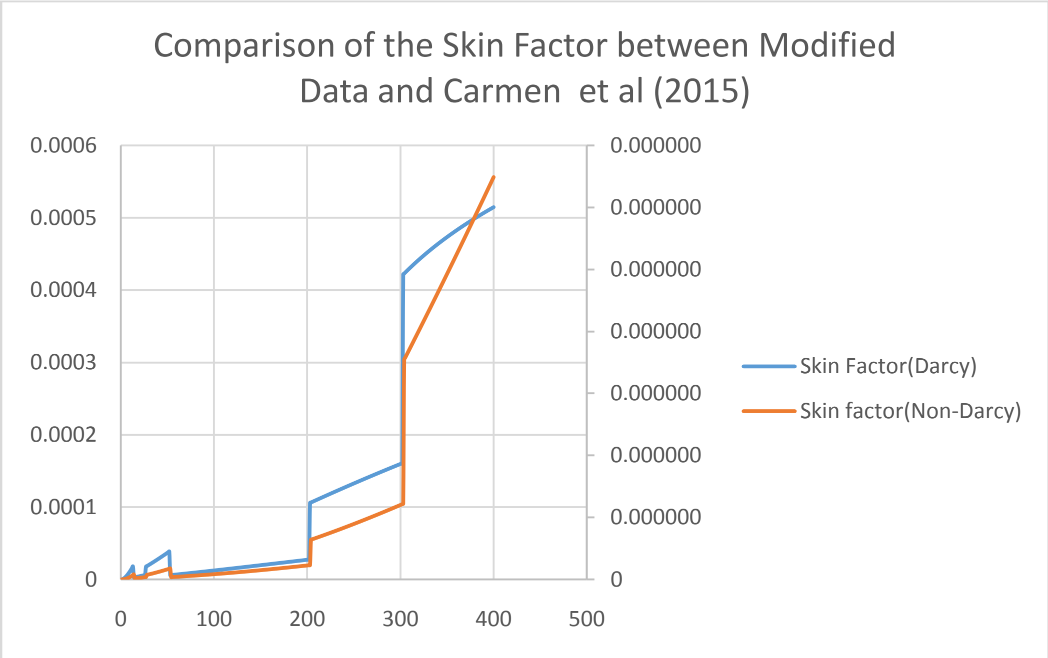

Figure 4. Plot showing the comparison between Modified skin Factor and Skin Factor of Carmen et al(2015)

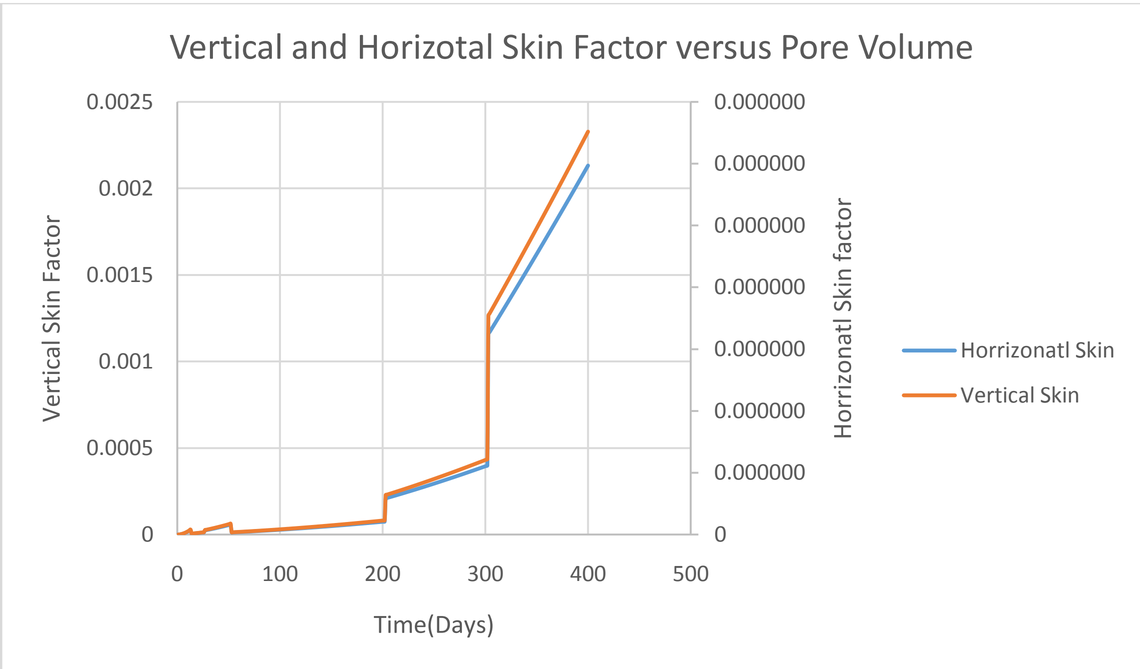

Figure 5. Plot showing the comparison of Vertical Skin and horizontal skin at 500m

Figure 4 shows both the modified model and the Carmen et al. model have almost similar skin of progression for the skin factor but they have different values of skin factor which are largely way apart. The plot shows non-Darcy skin has a lower skin factor compared to the Darcy Skin factor by Carmen et al.(2015).

At depth of 500m figure 5 shows that the vertical and horizontal skin factor increases both vertically and laterally, with the vertical scale having a higher skin compared to the horizontal skin.

III. CONCLUSION

It can be concluded from the tables and plots that the modified model can be used for prediction of permeability reduction as the permeability values are close to the actual values gotten from the reservoir.

The model can be used to predict permeability reduction due to scale at both narrow and tight pore throat which would have high velocity using non-Darcy flow.

The model also shows the skin factor and pressure drop increases with time. The model shows that non-Darcy skin factor is lower than the Darcy skin.

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Nomenclature

C	Concentration, g/cm^3
C(I)	Scale Concentration at the well bore pressure,mg/L
Kdep	Constant depsotion rate, m3/gs
□ □	Coefficient of Formation damage
P	Pressure, psi
q	Flow rate, STB/D
t	Time,hr
r	Radius, ft
r_s	Radius of skin
B	Formation volume factor, dimensionless
S_{wi}	Initial water saturation
S	Fraction of pore volume occupied by scale
s	Skin Factor
φ	instantaneous porosity, dimensionless
Φ_o	intial porosity, dimensionless
K	Instantaneous Permeability, m^2
K_o	Initail Permeability, m^2
h	Thickness, m