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Numerical Evaluation of Formation Damage Models for Application in Niger Delta Oil Reservoirs

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Abstract—*The frequent random application of formation damage models in the assessment of oil well deliverability has prompted the critical evaluation of these models to streamline their applicability in specific reservoir types. Coupled with the unconsolidated nature of the Niger Delta Agbada formation, the establishment of a unique damage model which will take into account, the textural and structural configuration of the formation sand in its damage estimation is most paramount. In this work, four formation damage models were numerically evaluated and matched to the conventional pressure buildup skin model using reservoir and well production data from five (5) different Niger Delta locations assigned ND-1, ND-2, ND-3, ND4 and ND-5. Result showed that the Frick & Economides model, if adopted within the region can be dreadful for all reservoir cases as it tends to underestimate formation damage implications as well as skin magnitudes since it is primarily a function of the altered permeability and damaged radius only, recording an average skin of 1.30 as against 3.36 for the reference model. The models of Behr & Raflee, Ozkan and Furui et al with reference to the buildup skin model showed promising results in skin magnitude estimation. Further damage analysis revealed that the Furui et al model was most appropriate as it yielded an average Flow Efficiency of 69.40%, an average skin induced pressure drop of 193.98 psi and an average damage factor of 0.3*

Keywords— Evaluation, Formation, Model, Niger Delta, Skin.

I. INTRODUCTION

The Niger Delta, proven to have an estimated reserve of about 37.2 billion barrels of oil is branded as one of the major oil and gas province within the Gulf of Guinea. Averaging an estimated daily withdrawal of 1.6 million barrels of oil per day, though greatly attributed to quite a number of socio- economic and political reasons, a good percentage of this reduction in daily production within the province can also be ascribed to a wide range of factors. These factors may be natural or incurred owing to high degree of uncertainties associated with oil and gas exploration. Uncertainties in petro-physical evaluation, reserve estimation, poor evaluation of target recovery mechanisms peculiar to specific reservoirs and many more may retard production benchmarks. Characterized by an unconsolidated sandstone formation, the Niger Delta oil bearing rocks have been thought and proven to suffer some reservoir rock-related productivity problems. These problems span from sand production as a result of the unconsolidated nature of the reservoir rocks to formation damage or permeability impairment, possibly as a result of fines migration and other sources.Formation damage in plain terms refers to the reduction of the permeability of the formation as a result of drilling, completion, production and injection operations. It is a peculiar problem in petroleum reservoirs, occurring in different stages of reservoir development from drilling to production and fluid re-injection. Over the years, quite a number of drilling and production practices have recorded significant losses in millions of recoverable barrels of oil and billions of cubic feet of gas. This invariably implies that formation damage phenomenon is absolutely unnatural to the reservoir flow channels within the wellbore vicinity which may impair the productivity of hydrocarbons from that reservoir.

It is convenient to say that all producing formations are depth filters, varying in shapes sizes and may contain constrictions where bridging of migrated particles can restrict flow. Also in highly reactive formations like shale with high percentage of clay mineral, heaving may contribute to formation damage when contacted with water molecules. The economic importance of formation damage phenomenon has prompted the evaluation of numerous mitigation methods by several scholars, who seek by experimental and mathematical methods, preventive techniques to mitigate these occurrences.

Traditionally, experimental studies in this regard have been for special case studies, peculiar to a particular environment without conjoining mathematical correlations which will provide a research springboard for future investigators.

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Despite the vast number of theoretical, experimental, and numerical studies on formation damage, a robust and comprehensively outstanding model capable of predicting the degree to which formation damage occur, especially within regions of poorly sorted petroleum formation such as the Niger Delta is paramount. The existence of such models is essential for successful development and design of damage mitigation processes. Most models have their validity based on experimentally obtained parameters from reservoir core samples under specific laboratory conditions. In this vain, their application is rather limited to field adaptations and as such, some sound level of model assumptions to adequately adopts these models to various reservoir types are requisite.

This damage phenomenon occurs not primarily by drilling and completion operations alone, but also occurs as a result of several complicated reservoir processes. Damage intensity can also be traceable to the flowing fluid properties and the geological orientation of the porous media i.e., the rock-fluid interaction. On this ground it is imperative that formation damage modeling must incorporate fluid-rock compatibilities, precipitation reactions, particulate processes in pore throats, swelling in reactive formations like clay, wettability, adsorption, absorption, net stress and compressive variations.

According to He *et al.*, 2002; Brandford *et al.*, 2010, subsurface fluids often contain in them suspended particles that may affect both flow and mechanical properties of the resident formation with time. Drilling mud infiltration into the near wellbore region, migration of fines, propant from hydraulic fractures, and contaminants from underground water are all a means by which formation damage can be quantified in a porous media.

In a bid to realize optimum recovery in oil and gas investments, it essential that all maximum well productivity techniques be explored. For this reason, identification and evaluation of effective formation damage models is paramount. Formation damage can occur at any point in the life of a reservoir from drilling, completion, work-over operations, well interventions and total depletion of the reservoir. This formation damage may be as a result of scaling and fine migration. (Schaible, *et al*., 1986; Mirabolghasemi, 2017).

Formation damage in petroleum reservoirs occurs as a consequence of the combined effects of several complicated processes. The extent of damage depends on the properties of the fluids and the geological configuration of the porous media, and the nature of fluid-fluid and rock-fluid interactions (Schaible, *et al*,. 1986). Therefore, formation damage modeling should account for fluid-fluid and rock-fluid incompatibilities, dissolution and precipitation reactions, pore deformation and collapse and sand production phenomena, particulate processes in porous structure, swelling of porous matrix and clay particles, effects of adsorption, (Civan, 2007; Ozkan and Raghavan, 1997; Mansoori, 1997).

The effect of skin can considerably reduce the production performance of any reservoir, be it sandstones, carbonates or shale. The skin phenomenon occurs when migrated fines are accumulated in and around the wellbore region as a result of production operations, drilling, workover, completion operations or even fluid injection operations. This phenomenon creates a distinction in the transmissibility of fluid in the reservoir, altering the permeability of the affected region.

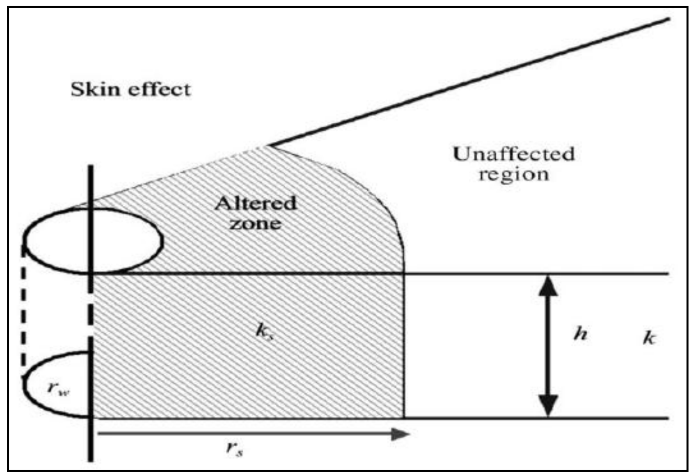

Fig.1: The 2-Region Reservoir Model Showing the Altered and Unaltered Zones

The 2-region reservoir model shown in Figure 1 is a convenient representation of a damaged wellbore region. Here, the altered zone is assumed to be of a uniform permeability k_s out to a radius r_s, beyond which the formation permeability, *k* is unaltered.

Using the 2-region model, the skin magnitude can be mathematically deduced with the following equation

$$s = \left(\frac{k}{k_s} - 1\right)\left(\frac{r_s}{r_w}\right) \tag{1.1}$$

Rearranging the above equation to resolve for the permeability of the altered zone, we obtain

$$k_s = \frac{k}{1+\frac{s}{\ln(r_s/r_w)}} \tag{1.2}$$

Having deduced the skin magnitude, it will be required to determine the additional pressure drop due to skin. This can be mathematically presented as;

$$\Delta p_s = \frac{141.2\, qB\mu}{kh} s \tag{1.3}$$

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Flow efficiency, E_f, in plain terms is defined as the ratio of the actual productivity index of the well (including skin) to the ideal productivity index if the skin factor were zero. since productivity index, J is the ratio of a stabilized flow rate to pressure drop required to sustain that stabilized rate, then

$$J_{ideal} = \frac{q}{\bar{p}-p_{wf}} \quad (1.4)$$

And

$$J_{actual} = \frac{q}{\bar{p}-p_{wf}-\Delta p_s} \quad (1.5)$$

The flow efficiency for such a system now becomes;

$$FE = \frac{J_{actual}}{J_{ideal}} = \frac{\bar{p}-p_{wf}-\Delta p_s}{\bar{p}-p_{wf}} \quad (1.6)$$

For a well with neither damage nor stimulation, $FE= 1$; for a damaged well, $FE< 1$; and for a stimulated well, $FE > 1$.

Rege and Scott-Fogler, in 2007 in an attempt to develop a radial model for formation damage in porous media, the authors observed that a continuous change in velocities in radial geometry have a significant effect on process characteristics, making it an intellectually challenging problem. In practical injection operations, fluids are injected down-hole and travel radially in the outward direction. They presented case studies for constant flow rate and constant pressure injections for which comparisons are made between linear and radial systems. Simulating this radial system with linear models was the primary target for their study. A radial network model, covering an angle of about 120° was developed to simulate formation damage due to deep bed filtration (DBF) of injected suspensions. The model when validated drew a previously developed concept of "wave-front movement" and "flow-biased probability" for linear systems using monodispersed and polydispersed suspensions. Results from their analysis showed that parameters so obtained from linear models were conventional when compared to results obtained from other radial models. He *et al*., (2013) developed a fluid-solid coupling finite element model to simulate and quantitatively analyze the pressure evolution in the reservoir as well as damage and permeability change in the formation during long-term water flooding process. Their obtained results provided a theoretical comprehension of the benefits (pore pressure increase in the simulation domain), rock damage, permeability change of long-term water flooding, and offered an in-depth knowledge on how to detect and prevent wellbore failure and collapse due to formation damage during water flooding.

Regardless of the numerous experimental studies on formation damage of oil and gas bearing formations, only very few attempts to adequately mathematically model the process have been done. The application of these models in actual reservoir analysis and management has been rather limited because of the difficulties in the understanding and implementation of these models. (Byrne and Rojas, 2013; Carpenter, 2017). Organic deposition both in and around the wellbore is perhaps the most prominent form of damage problem reported in the mature oil-producing reservoirs worldwide. These organic deposits fall into two broad categories, paraffins and asphaltenes. Paraffins and asphaltenes can deposit both in tubing and in the pores of the reservoir rock, significantly limiting well productivity (Petrowiki, 2015). The plugging of reservoir-rock pore throats can be caused by the fine solids found in mud filtrate or in solid particles dislodged by a filtrate within the rock matrix. In order to reduce this, it is often a common practice to encourage using nano sized solid particles in mud preparation when designing to counteract fluid losses (Zain, and Sharma, 2000). Buildup of fine particles being transported, particularly in sandstone reservoirs, can significantly reduce well productivity due to the mobile nature of particles, particularly in unconsolidated system. Direct evidence of migrated fines-induced formation damage in production wells are usually difficult to be encountered (Aristov *et al*., 2015). While other mechanisms of formation damage have obvious indicators of the phenomenon, field indications of fines migration are much more elusive. Indirect evidence such as declining productivity over a period of several weeks or months is the most common symptom. This reduction in productivity can usually be reversed by mud-acid treatments. A large number of wells around the world follow these patterns of reduction of productivity followed by significant improvements when subjected to a mud-acid treatment. This behavior most often suggests a buildup of fines in the near-wellbore region over a period of time (Nguyen *et al*., 2013; Olivera *et al*., 2014). Field studies and laboratory experiments have indicated that the fines causing the permeability reduction include clays, feldspars, micas, and plagioclase. Because the mobile fines are made up of a wide variety of minerals, the clay content of the reservoir may not always be a good indicator of the water sensitivity of the formation (Gray and Rex, 1996). Owing to the fact that reservoir rock property classification vary from place to place possibly as a result of several geological and stratigraphic configuration, it may be convenient to conclude that the adaptation of petro-physical properties of reservoir rocks for formation damage modeling should be exclusive to a particular model that can accurately mimic the candidate reservoir system. Over the years, there have been quite a number of formation damage reviews but none in recent time, pertinent to its applicability within the Niger Delta formations has yet been established. It is therefore important that that the establishment of suitable formation damage models via sound engineering evaluations be implemented, putting in to consideration, the petro-physical properties peculiar to the region. Several Mathematical models in conjunction laboratory evaluations have provided some degree of comprehension into the spatial development and quantification of formation damage. For example if suspended colloidal particles /or formation grains carry electrostatic charges, particles might attach to the grains' surface and get entrapped. This phenomenon has classically been modeled by the \single collector model (Zamani and Maini, 2009).

A variety of studies have been done to quantify formation damage and formulate it in terms of permeability impairment as a function of time and properties of flow, suspended particles, and porous media. Moreover, industrial standard measures pertinent to reservoirs are in place, many of which are only applicable under limited circumstances. For example, a common rule of thumb is if particles been are greater than 33% of the median pore throat diameter, they will form stable bridges which can cause permeability reduction. While this is only valid for turbulent flow, particles as small as 7% of the median pore throat size have the ability to plug the pores in laminar flow cases (Blyton *et al.*, 2017). This, however, lack of a global criterion for particulate bridging implies that a thorough comprehension of the phenomenon of formation damage entails a comprehensive study of all of the contributing factors and mechanisms (Mirabolghasemi, 2017)

Fallah and Sheydai, (2013),revealed that, near wellbore mud the resulting formation damage considered one of most encountered problems involving the petroleum reservoir exploitation. They assumed suspension concentration which was based on the fact that for each flow velocity there does exist the maximum amount of retention particles that electric-molecular forces can keep. The dimensionless erosion number, which is ratio between the cross flow drag force and the total of normal forces, is proportional to flow velocity. The stabilization phenomenon was characterized by so called storage capacity which is the maximum retention concentration versus erosion number. Nmegbu, (2014) in an attempt to model for quantitative formation damage in oil the reservoir during microbial enhanced oil recovery shows that for a continuous microbial injection operation, the total pore area of the formation decreases in an equivalent percentage via the microbial plugging and biomass accumulation mechanisms within the reservoir. The prevailing effects of formation damage due to these microbes were also presented with residual fluid flow rates and corresponding velocities decreasing in magnitude fter several days of microbial injection. The author presented a second order PDE which was resolved using the Explicit Finite Difference Approximation method. The model was to estimate the pore area reduction in the reservoir due to biomass accumulation.

II. MATERIALS AND METHODS

The fundamental principles upon which the formation damage (skin) models will be evaluated will include the damaged zone permeability assessment, analytical evaluation of formation permeability via well test analysis (particularly for pressure buildup transient test), flow efficiency analysis, skin induced pressure models and damage intensity. Field parameters were collected form five reservoirs at different locations within the Niger Delta. The selection process was influenced by the research scope which as earlier stated, will consider and limit this analysis to oil reservoirs only within the region. These parameters comprised of data obtained from four onshore operators and an offshore operator. With each field producing at a desired optimum production constraint and with adequate sand control measures in place, sand production data was also obtained. The nomenclature assigned to each location is ND-1, ND-2, NG-3, ND-4 and ND-5, with ND-5 being the only offshore field amongst all five operators.

2.1 Damage (Skin) Models to be Evaluated

2.2.1. Frick and Economides Model

In the estimation of equivalent skin factor, assuming both conically and cylindrically shaped damaged zone and putting into consideration the net pay thickness of the reservoir pay interval, the magnitude of formation damage will be estimated using that presented by Yildiz, (2008);

$$S_{FE} = \left(\frac{\mathrm{k}}{\mathrm{k_d}} - 1\right) \ln\left(\frac{1}{3}\sqrt{\frac{\mathrm{r_{dh}^2}}{\mathrm{r_w^2}}} + \frac{\mathrm{r_{dh}}}{\mathrm{r_w}} + 1\right) \qquad (2.1)$$

Where;

S_{FE} Dimensionless Frick and Economides skin factor.

k is the average undamaged reservoir permeability, mD

k_d is thedamaged reservoir permeability, mD

r_{dh} is the damaged radius for the payzone, (ft)

r_w is the wellbore radius, (ft)

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2.2.2 Furui *et al.*, Model

$$S_{(x)} = \left[\frac{\mathrm{k}}{\mathrm{k}_{\mathrm{d(x)}}} - 1\right] \ln\left[\frac{1}{\mathrm{I}_{\mathrm{ani}} + 1}\left(\frac{\mathrm{r}_{\mathrm{d(x)}}}{\mathrm{r}_{\mathrm{w}}} + \sqrt{\left(\frac{\mathrm{r}_{\mathrm{d(x)}}}{\mathrm{r}_{\mathrm{w}}}\right)^2 + \mathrm{I}_{\mathrm{ani}}^2 - 1}\right)\right] \quad (2.2)$$

$$\mathrm{I}_{\mathrm{ani}} = \sqrt{\frac{\mathrm{k}_{\mathrm{H}}}{\mathrm{k}_{\mathrm{V}}}}$$

Where;

$S_{(x)}$ Dimensionless skin factor at damaged radius x

k is the average undamaged reservoir permeability, mD

k_d is thedamaged reservoir permeability, mD

I_{ani} is the anisotropic index, Dimensionless

$r_{d(x)}$ is the damaged radius, (ft)

r_w is the wellbore radius (ft)

k_H is the horizontal permeability of the reservoir, mD

k_V is the vertical permeability of the reservoir, mD

Accounting for the effect of formation damage on well productivity, the ratio of the productivity index for a damaged well to that of an undamaged well can be deduced using;

$$\frac{J_d}{J} = \frac{\ln\left[\frac{\mathrm{h\ I_{ani}}}{\mathrm{r_w(I_{ani}+1)}}\right] + \frac{\pi\ \mathrm{y_b}}{\mathrm{h\ I_{ani}}} - 1.224}{\ln\left[\frac{\mathrm{h\ I_{ani}}}{\mathrm{r_w(I_{ani}+1)}}\right] + \frac{\pi\ \mathrm{y_b}}{\mathrm{hI_{ani}}} - 1.224 + S_{(x)}} \quad (2.3)$$

2.2.3. Behr and Raflee Model

In the assessment of reservoir pressure support induced formation damage, the Behr and Raflee particle induced skin account is presented in equation (3.04) below;

$$S_p = S_i\left(\eta_{\mathrm{w}}\frac{\mathrm{r_w}}{\mathrm{r_R}}\right)^{1-\mathrm{n}} + \frac{1}{1-\mathrm{n}}\left[\left(\frac{\mathrm{r_e}}{\mathrm{r_R}}^{1-\mathrm{n}} - \frac{\mathrm{r_p}}{\mathrm{r_R}}^{1-\mathrm{n}}\right)\right] + \omega^{1-\mathrm{n}}\frac{\mathrm{r_p}^{(\beta+1)(1-\mathrm{n})} - \mathrm{r_w}^{(\beta+1)(1-\mathrm{n})}}{(\beta)(1-\mathrm{n})\mathrm{r_R}^{1-\mathrm{n}}} - \ln\left(\frac{\mathrm{r_e}}{\mathrm{r_w}}\right) \quad (2.4)$$

$$\omega = \frac{1}{\mathrm{r_p}^{\beta}} = \frac{\eta_{\mathrm{w}}}{\mathrm{r_w}^{\beta}} \quad (2.5)$$

$$\beta = \frac{\ln(\eta_{\mathrm{w}})}{\ln\left(\frac{\mathrm{r_w}}{\mathrm{r_p}}\right)} \quad (2.6)$$

$$r_R = \sqrt{r_w\, r_a} \quad (2.7)$$

Where;

S_p is the Dimensionless particle induced skin factor

S_i is the Hawkins deduced skin factor

η_w is the Dimensionless coefficient of completion for an oil well (0.50)

r_R is the equivalent radius, ft

r_w is the wellbore radius, ft

r_e is the reservoir radius, ft

r_a is the aquifer radius, ft

r_p is the radius of the sandstone particle, ft

n is the dimensionless tortuosity index for porosity range.

Though Equation (2.4) was originally modelled for a polymer injection process, with power law index of injected fluid *n*, this study replaces the power law index with the tortuosity parameter for each case study. The adaptation of the model to this study is validated since the value of the power law index in the study of Behr and Raflee falls within the tortuosity range of the various case studies to the analyzed.

Therefore, the tortuosity of each reservoir sand foran overlapping circular-shaped sandstone formation as approximated in 1989 by Comiti *et al.*(Comiti *et al.*, 1989) will be deduced using Equation (2.8) below;

$$\tau = 1 + ꝑ\, ln\emptyset \quad (2.8)$$

Where;

τ is the dimensionless tortuosity magnitude.

ꝑ is the formation packing factor for sandstone

$\emptyset$ is the formation porosity

2.2.4. Ozkan Model

The derived expression for the determination of formation damage magnitude and additional pressure drop caused by the region of altered permeability around the wellbore as presented by Ozkan, (1997) at time, t and distance, r is given by;

$$S_{Om} = \frac{\mathrm{P_{wf_{r,x,t)}}} - \mathrm{P_{s_{r,x,t)}}}}{\frac{\mathrm{L\ k_{\tilde{r}}}}{\mathrm{h\ k}}\left(\tilde{\mathrm{r}}\frac{\partial \mathrm{p}}{\partial \mathrm{r}}\right)_{(\mathrm{r,x,t})}} = \frac{\frac{\mathrm{k\ h}}{141.2\ \mathrm{q}\ \mu\ \mathrm{B}}\Delta \mathrm{P_s}}{\mathrm{q_D}} \quad (2.9)$$

$$\mathrm{q_D} = \frac{\mathrm{q_{sc(r,t)}}L}{q} = \frac{\mathrm{L\ k_{\tilde{r}}}}{141.2\ \mathrm{q}\ \mu\ \mathrm{B}}\left(\tilde{\mathrm{r}}\frac{\partial \mathrm{p}}{\partial \mathrm{r}}\right)_{(\mathrm{r,x,t})} \quad (2.10)$$

Where

$$\mathrm{k_{\tilde{r}}} = \sqrt{\mathrm{k_y k_x}} \quad (2.11)$$

$P_{wf(r\ ,x,t)}$ is the wellbore flowing pressure at time t, psi

$P_{ws(r,x,t)}$ is the pressure of the radial damaged interval r, at time t, psi

L is the length of the well, ft

q_d is a dimensionless flux quantity

q_{sc} flux at the well surface, bbl/day/ft

$k_{\tilde{r}}$ is the equivalent permeability of the x-y plane.

$\frac{\partial p}{\partial r}$ is the defined pressure derivative obtained from a transient test plot

2.2.5. The Conventional Transient Test skin Model

Evaluating the above models, deductions form each model will be compared to a pressure buildup transient test skin model. This is because available field data is made up of

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pressure buildup parameters among others. The pressure buildup skin model is thus given as;

$$s = 1.151\left[\frac{P_{1hr}-P_{wf}}{m} - \log\frac{k}{\emptyset\mu c_t r_w^2} + 3.227\right] \qquad (2.12)$$

Where;

$\emptyset$ is the porosity of the reservoir

μ is the oil viscosity (cp)

c_t is the total compressibility of the reservoir system, (psi^{-1})

r_w is the radius of the wellbore, (ft)

P_{1hr} pressure interpolation on the Horner's plot at dt=1, (psi)

P_{wf} is the wellbore flowing pressure before shut-in, (Psi)

m is the slope of the Horner's plot, (psi/cycle).

One of the ways in which the productivity of a nonzero skin or non-zero formation damage is quantified is by the Flow Efficiency deduction. Denoted by the symbol F.E, it will be obtained through taking a ratio of the actual productivity index of each well (including skin) to the ideal productivity index if the skin factor were zero. Because the productivity index is the ratio of stabilized flow rate to pressure drop required to sustain that stabilized rate, the productivity indexes is presented in Equations (2.13) and (2.14) respectively.

$$PI_{actual} = \frac{q}{(\bar{P}-P_{wf})} \qquad (2.13)$$

$$PI_{ideal} = \frac{q}{(\bar{P}-P_{wf}-(\Delta P_s))} \qquad (2.14)$$

Consequently, the flow efficiency can be presented as;

$$F.E = \frac{PI_{actual}}{PI_{ideal}} = \frac{(\bar{P}-P_{wf}-(\Delta P_s))}{(\bar{P}-P_{wf})} \qquad (2.15)$$

For a well with neither damage nor stimulation, F.E = 1; for a damaged well, F.E < 1; and for a stimulated well, F.E > 1.
Again, it is important to note that for this study, the wells of interest from the various locations have no records of well stimulation(matrix acidizing or hydraulic fracturing) performed on them for the past 10 years. This is a desired analytical constraint because accurate flow efficiency estimation for ND will be distorted and results may truncate model choice of model establishment on completion of study.

Equation (2.15) will be adopted for the efficiency of flow of the well in a damaged subjected scenario for all 5 selected models

Damage intensity of models will be evaluated in terms of Damage factor and Damage ratio. Damage factor is a dimensionless quantity used to evaluate the fractional percentage of production performance as a function of the damaged or altered permeability around the wellbore. Mathematically, it is presented as;

$$DR = 1 - F.E \qquad (2.19)$$

Damageratio will be used to evaluate the magnitude of the skin induced productivity for each model. It will be calculated using Equation (2.20) below

$$DR = \frac{1}{F.E} \qquad (2.20)$$

III. RESULTS AND DISCUSSION

Having computed reservoir rock and fluid data, production data, well parameters and other requisite parameters from five different Niger Delta reservoirs, a Matlab R2007 a program was written to generate a series of formation damage (skin) magnitudes for all five (4) models (Frick and Ecomindes model, Furui *et al.*, model Behr & Raflee model and Ozkan model) with the nomenclatures; s_FE, s_F, s_BR and s_O and that of the buildup obtained skin being s_i.

The four models were however matched and compared to the skin equation for a buildup pressure transient test. Permeability function for each model was also deduced from the transient test plot. These results were obtained for all five Niger Delta reservoirs (ND-1, ND-2, ND-3, ND-4 and ND-5). Graphical representation of these variations in skin magnitudes for each model is presented in Figure 2, 3, 4, 5 and 6 for all five reservoirs ND-1, ND-2, ND-3, ND-4 and ND-5 respectively.

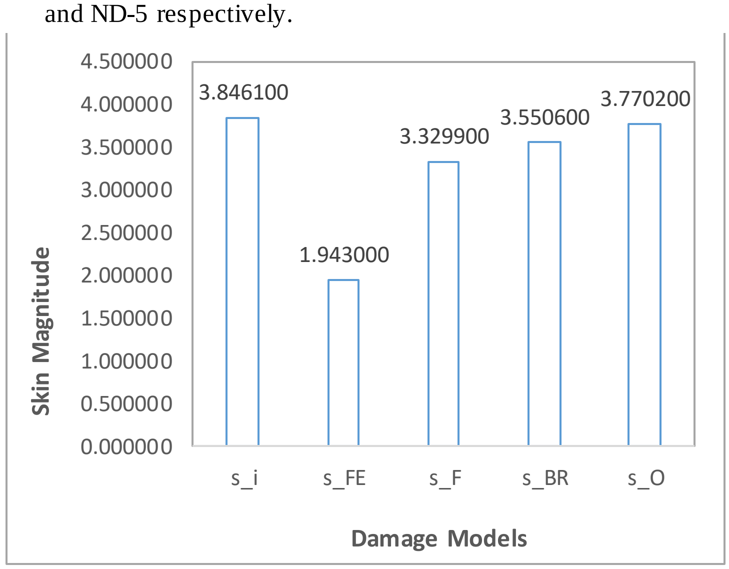

Fig.2: Formation Damage Magnitude (Skin) for Each Damage Model for ND-1

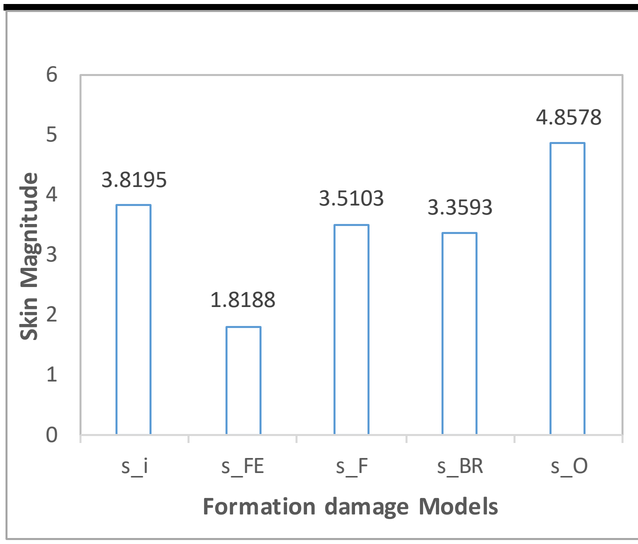

Fig.3: Formation Damage Magnitude (Skin) for Each Damage Model for ND-2

With the buildup obtained skin (s_i) being the reference for the evaluation of all others for the ND-1 reservoir, it can be inferred from Figure 2 that Ozkan's skin model, (s_O) recorded the closest to the buildup obtained skin (s_i), recording about 3.77 as against the buildup obtained skin of 3.85. Frick and Economides model under estimated the skin magnitude, recording about 1.94 damage to the formation.

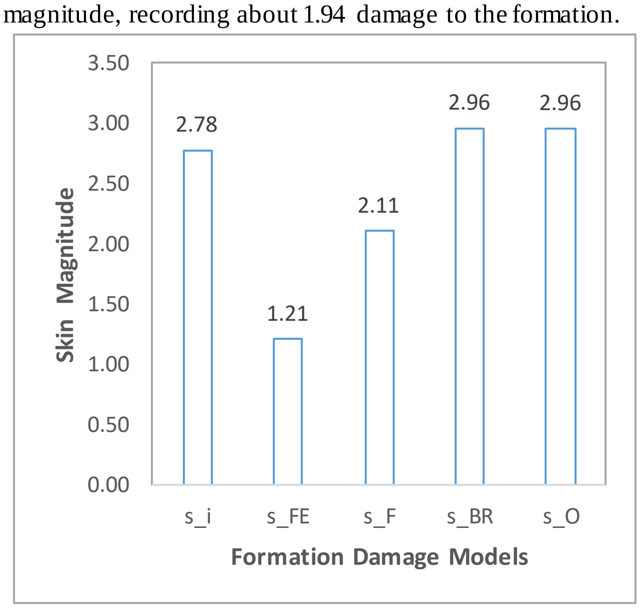

Fig.4: Formation Damage Magnitude (Skin) for Each Damage Model for ND-3

For ND-2 reservoir, the Frick & Economides skin model, (s_FE) also under estimated the formation damage magnitude by recording 1.82 as against the buildup obtained skin (s_i) which was 3.51. as shown in Figure 4.2. The closest to the buildup skin (s_i) was that of the Furui et al, (s_F) which was 3.81 and that of Ozkan overestimated the skin magnitude, recording about 4.86 which when used for future reservoir performance forecast may prove erroneous in some flow and productivity analyses.

Figure 4 above shows that for the ND-3 reservoir, the damage models for Oskan and that of Behr and Raflee can be used to estimate skin magnitude as it tends to have a closer reading to that of the reference skin model. Both having 2.96 as against 2.78 for that of the Buildup obtained skin magnitude, shows a considerable level of applicability. Again, for this reservoir, the skin estimation obtained from Frick and Economides model cannot be adopted as it shows an underestimation of formation damage in the magnitude 1.21.

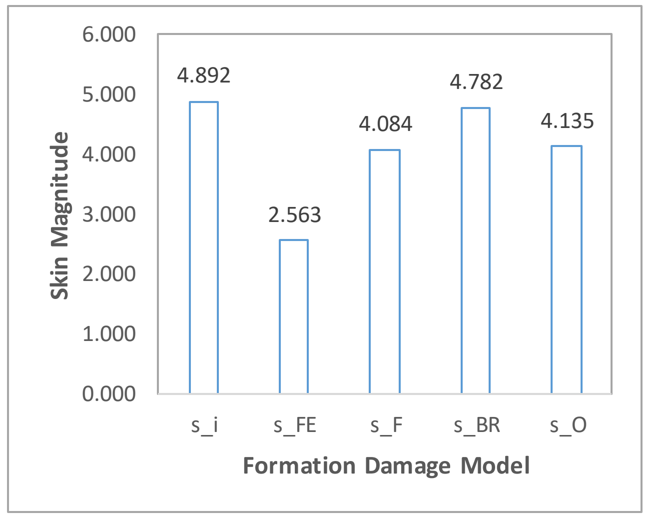

Fig.5: Formation Damage Magnitude (Skin) for Each Damage Model for ND-4

The ND-3 reservoir, having computed all reservoir rock and fluid parameters for skin estimation saw to the adaptation of the s_BR model as it recorded a damage magnitude of 4.78 as against the buildup damage estimation of 4.89. The Ozkan and Furui *et al* model slightly underestimated the damage magnitude as they both recorded4.14 and 4.08 respectively. At this point it is convenient to ascertain that the skin estimation form Frick and Economides cannot be used for damage analysis as it has proven to underestimate four reservoir skin magnitudes as shown in Figure 5 above.

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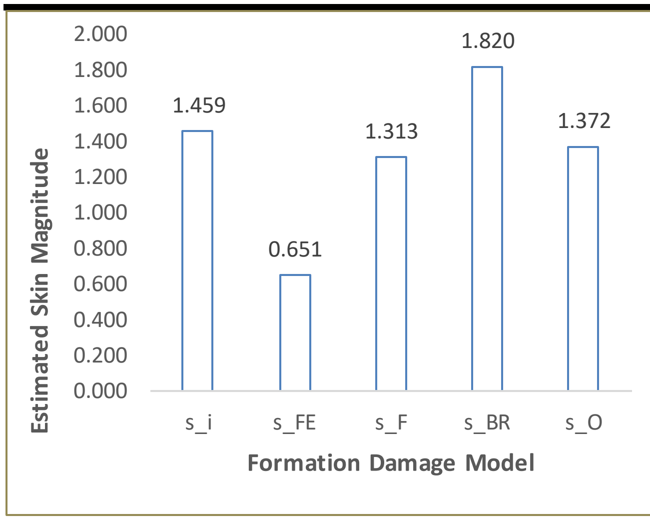

Fig.6: Formation Damage Magnitude (Skin) for Each Damage Model for ND-5

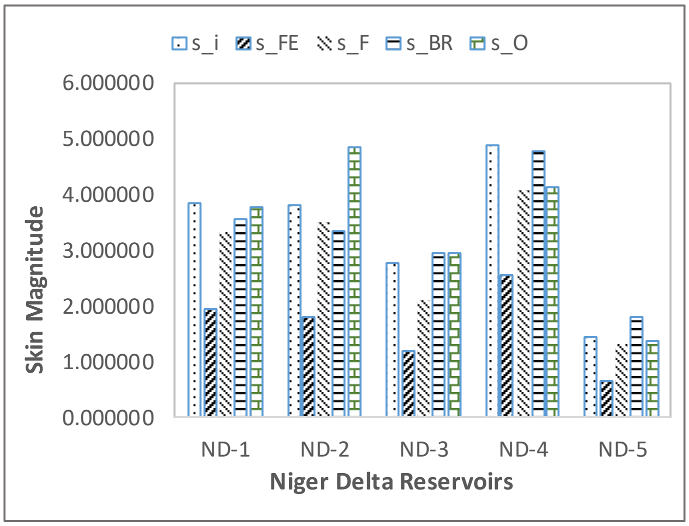

Fig.7: Summary of Skin Magnitudes for Models for all five oil Reservoirs

The model for Ozkan and Furui *et al* showed an encouraging applicability in the offshore reservoir, ND-5 as shown in Figure 6 above. The Behr and Raflee model was observed to have overestimated the formation damage magnitude by 20% recording about 1.820 in skin magnitude as against the 1.459 skin magnitude from buildup skin estimation. The 55.4% underestimation of formation damage by the Frick and Economides model shows that sound engineering of reservoirs in offshore locations cannot be achieved using it as it tends not to proffer proximate skin values, It can be inferred from Figure 7 that the recurrent underestimation of formation damage from the Frick and Economides model is traceable to the fact that it does not incorporate certain intricate reservoir parameters that can influence formation damage. It seemed to be the simplest expression, having only damage radius and damaged permeability considerations, tending to ignore other relevant parameters such as sand grain sizes, anisotropy of the system, tortuosity and other relevant parameters, especially for a Niger Delta oil bearing formation that is characterized to the well sorted but poorly unconsolidated.

3.1 Pressure Drop Evaluation

3.1.1 Skin Induced Pressure Drop

The additional pressure drop due to skin ΔP_s was calculated for each model using the Hawkins expression for all five reservoirs. Simulation results showed that the skin induced pressure drop for all models had an equivalent weighted average to their corresponding formation damage magnitudes. Figure 8 below shows the variation in formation damage magnitude and the corresponding skin induced pressure drop, ΔP_s for all five damage models in ND-1.

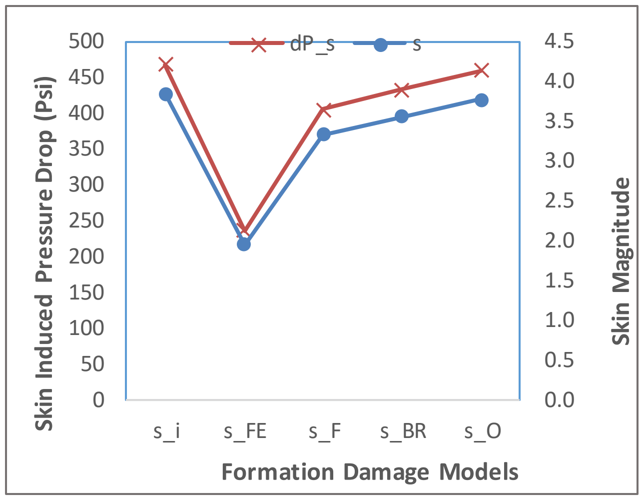

Fig.8: Variation in Formation Damage Magnitude for all Damage Models with their Corresponding Skin Induced Pressure Drop, (ΔP_s) for ND-1.

Here, it is observed that a skin magnitude of 3.8 yielded a corresponding pressure drop in the magnitude of 467.92 psi for the buildup obtained model. The closed to this model as earlier stated and observed in Figure 4.1 is that of the Ozkan model, recording an equivalent pressure drop of 458.67 psi for a skin magnitude of 3.77.

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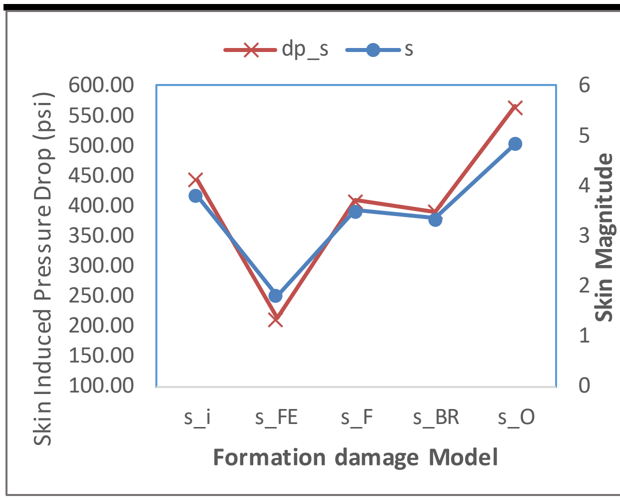

Fig.9: Variation in Formation Damage Magnitude for all Damage Models with their Corresponding Skin Induced Pressure Drop, (ΔP_s) for ND-2.

As shown in Figure 9 the Buildup skin model and the Furui *et al* model with skin magnitudes of 3.82 and 3.51 respectively was observed to be slightly similar in skin estimation for the ND-2 reservoir. Both yielding an average pressure drop due to skin in the magnitude of 444.77 psi and 408.76 for the Buildup model and that of Furui *et al* respectively. This 9% variation in pressure drop analysis between both models makes it imperative that the Furui *et al* model, compared to all others proves a better option for the ND-2 field.

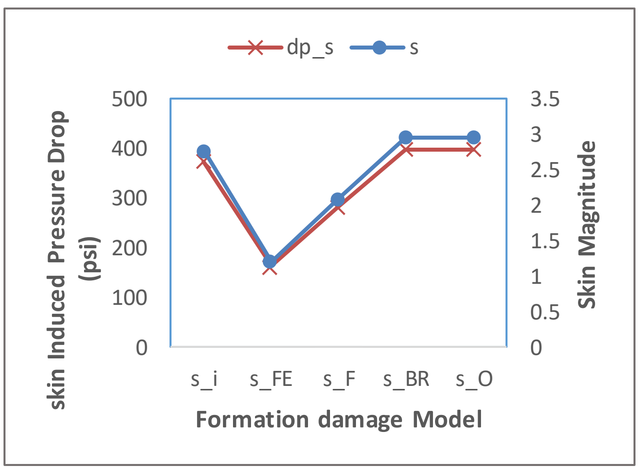

Fig.10: Variation in Formation Damage Magnitude for all Damage Models with their Corresponding Skin Induced Pressure Drop, (ΔP_s) for ND-3.

Skin induced pressure drop **(ΔP_s)** analysis for the ND-3 reservoir revealed that since both the Ozkan and BR models had a close prediction of formation damage in the magnitude of 2.96 for both models as compared to 2.78 skin magnitude for the buildup model, it can be inferred that for reservoirs producing within a rate of 800 stb/day range, both models can be adopted . With a 0.06% deviation from the reference model for both damage models with respect to pressure from due to skin, we can conclude that s_{BR} and s_O can be adopted for intermediate production reservoirs within the Niger Delta.

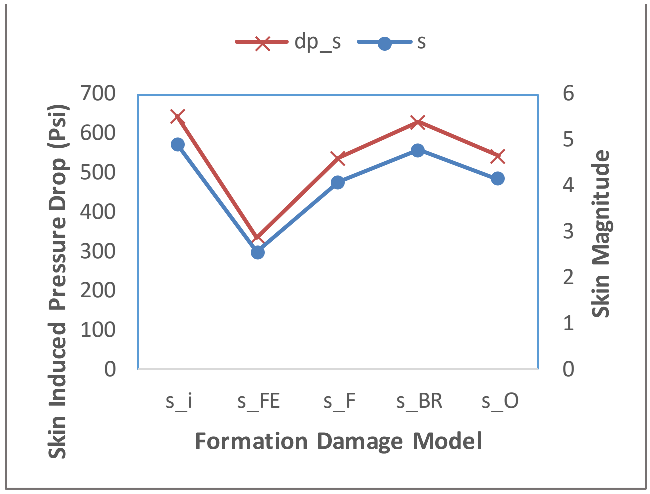

Fig.11: Variation in Formation Damage Magnitude for all Damage Models with their Corresponding Skin Induced Pressure Drop, (ΔP_s) for ND-4.

The parameters from the offshore field showed a perfect superimposition for both formation damage magnitude and its equivalent pressure drop due to skin for all five models as presented in Figure 12 below. This is to say that a skin estimation of any magnitude, regardless of the authenticity or applicability of the model in the environment can yield a perfect and optimum pressure drop with its corresponding formation damage degree.

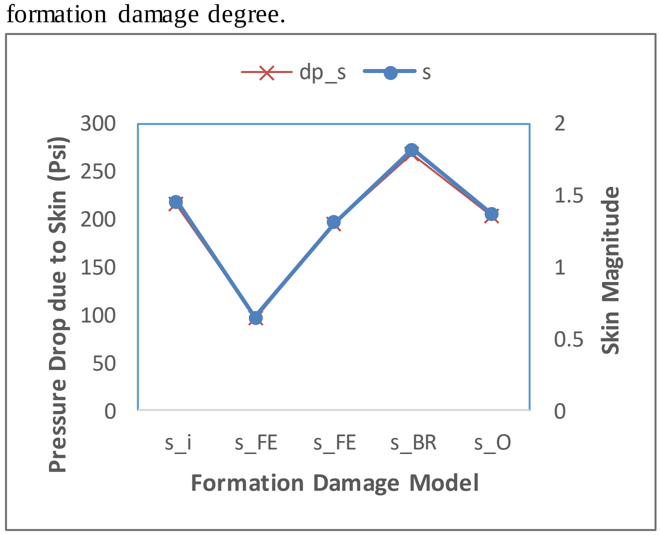

Fig.12: Variation in Formation Damage Magnitude for all Damage Models with their Corresponding Skin Induced Pressure Drop, (ΔP_s) for ND-5.

The underestimation of skin and formation damage losses in pressure for the Frick and Economides model (s_FE) in all five distinct reservoirs goes a long way to confirm that skin magnitude estimation within the Niger Delta is not just a function of the damaged radius and damaged permeability, but also a function of certain petro physical properties peculiar to the Niger Delta region.

3.2. Reservoir Flow Performance

3.2.1 Flow Efficiency Analysis

A unique method for the examination of formation damage translation to a physically meaningful characterization of our candidate Niger Delta reservoirs is by using the Flow Efficiency, (F.E) analysis. The adoption of Equation (2.15) and accurate simulation via Matlab R2007b with reservoir parameters for all five reservoirs and deductions from pressure transient analysis is represented in figure 18 to 22.

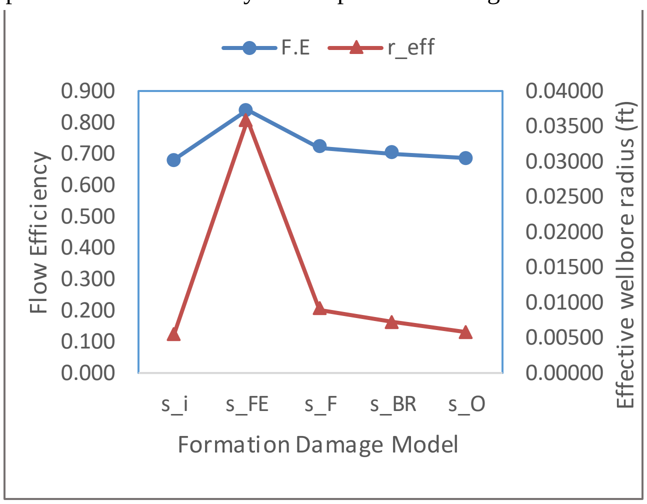

Fig.13: Variation in Flow Efficiency and Effective Wellbore Radius for all Evaluated Damage Models in ND-1

The 83.7% prediction of Flow Efficiency by the Frick and Economides model on the ND-1 reservoir may seem convincing and may influence the choice of model adaptation to reservoirs of such like properties. However, the non-incorporation of skin dependent parameters besides damaged permeability and damaged radius in the model has prompted this model to ignore certain intricate formation damage functions and thus tends to predict a high flowefficiency of 83.7%. This is as a result of the underestimation of the pressure drop due to skin, (ΔP_s) by the model which records just about 236.39 psi.

With the reference model recording a 67.7% flow efficiency prediction for this reservoir at a pressure drop due to skin, (ΔP_s) of 467.92 psi, parameter and simulation studies revealed that the Ozkan model had a closer prediction of Flow Efficiency to the reference, recording a Flow Efficiency of 68.36% at a corresponding pressure drop due to skin of about 458.68 psi. The Furui *et al* and BR models had a higher flow efficiency estimation of 72.1% and 70.2% at their corresponding pressure drops due to skin (ΔP_s) of 405.12 psi and 431.97 psi respectively.

Figure 14 shows a 59.5% flow efficiency from pressure buildup skin model for reservoir ND-2 at a corresponding pressure drop, (ΔP_s) of 444.77 psi. Here, the Furui *et al*model shows a better result in terms of similitude to the reference model, having a 408.76 psi skin induced pressure drop and a corresponding flow efficiency estimation of 62.77 %

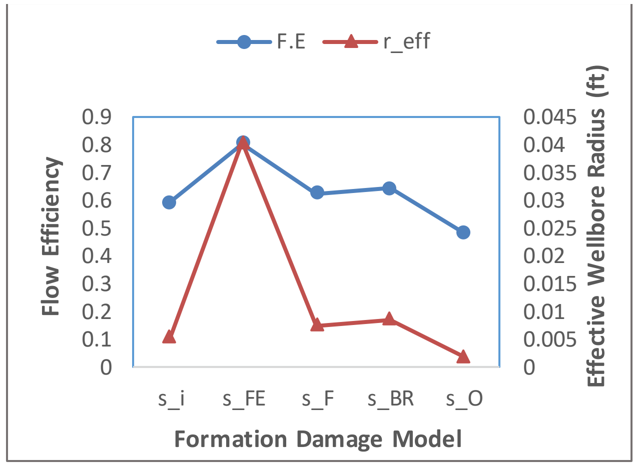

Fig.14: Variation in Flow Efficiency and Effective Wellbore Radius for all Evaluated Damage Models in ND-2

Closer to the Furui *et al* model was that of the Behr and Raflee model, having a pressure drop of 391.98 psi and a 64.37% flow efficiency performance. The Ozkan model showed a larger percentage difference from the reference with a 21.37% deviation in skin induced pressure drop magnitude and a 9.3% variation in flow efficiency for the ND-2 reservoir.

For the ND-3 reservoir shown in Figure 15, the model Behr & Raflee and that of Ozkan predicted a closely related flow efficiency percentage of 64.39 and 64.45 respectively, both with a 4% deviation from our reference model irrespective of their skin induced pressure drop.

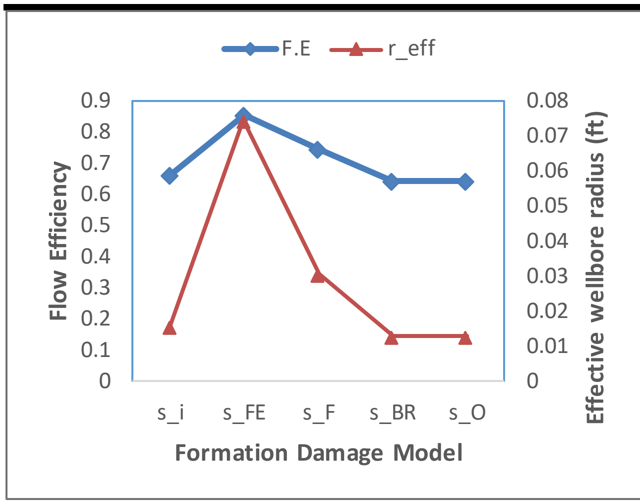

Fig.15: Variation in Flow Efficiency and Effective Wellbore Radius for all Evaluated Damage Models in ND-3

The 74.71% estimation of flow efficiency for the Furui *et al* model still falls within a 9.5% deviation range from that of the buildup formation damage model. The Furui *et al* model may be adopted for this reservoir when all requirements and reservoir parameters available can accurately be simulated, provided there is a less impact on anisotropy in the candidate reservoir as the model emphasizes the importance of anisotropy in formation damage evaluation.

The Behr & Raflee model also shows a good application in the ND-4 reservoir in terms of well flow efficiency as it records a 49.76% F.E as against 48.61% for that of the reference model as shown in Figure 16

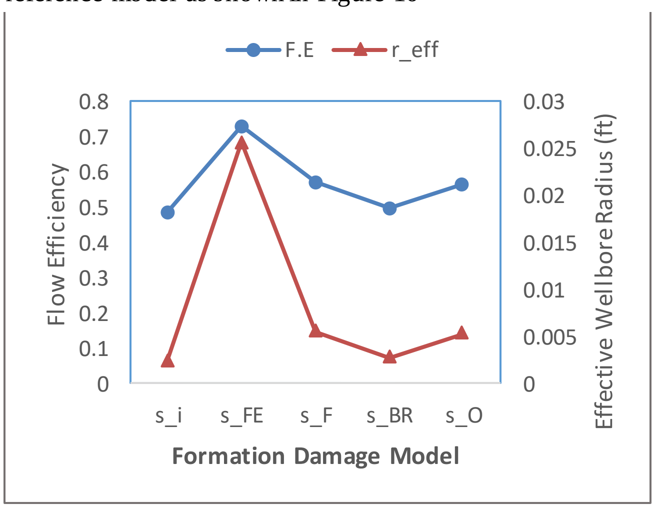

Fig.16: Variation in Flow Efficiency and Effective Wellbore Radius for all Evaluated Damage Models in ND-4.

The models for Ozkan and Furui *et al* also showed proximal flow efficiency predictions but were rather than that of the B-R model, with both having 56.56% and 57.09% flow efficiency estimations. This is as a result of their low formation damage prediction which naturally tends to overestimate the reservoir production performance and efficiency.

In the analysis of the offshore reservoir of ND-5, the Furui et al model once again showed a good applicability in terms of flow efficiency analysis. Figure 4.16 reveals that a Furui *et al* obtained flow efficiency of 82.24% can match up to an 80.26% flow efficiency for that of the reference buildup damage model. The ozkan model can also be applied as it showed a closer flow efficiency estimation of about 81.43% with a corresponding pressure drop due to skin of 202.75 psi as against the 215.58 psi drop in pressure from the reference model.

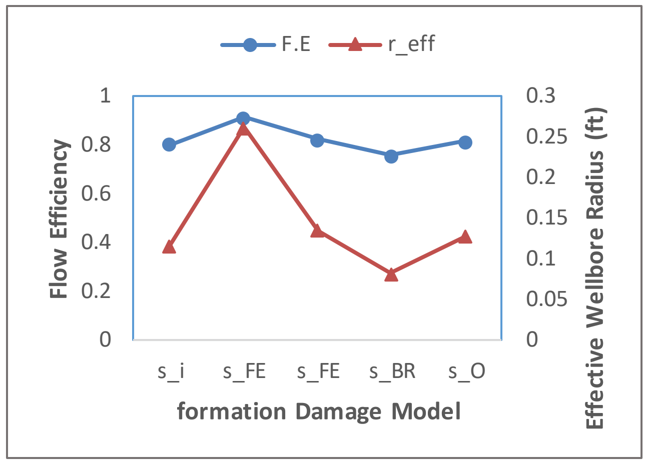

Fig.17: Variation in Flow Efficiency and Effective Wellbore Radius for all Evaluated Damage Models in ND-5

As usual, the Frick and Economides model as presented by Yildiz in 2008 on evaluation via reservoir parameter simulation with Matlab continuously underestimated formation damage magnitudes, predicted a lower pressure drop in an actual case scenario and overestimated well productivity performance by recording very high flow efficiencies for all five (5) reservoirs that have been investigated.

3.3 Damage Intensity Analysis

3.3.1 Damage Factor – Flow Efficiency Relationship

The damage factor expression from Equation (3.13) yielded a series of deductions from all 5 models for the five (5) Niger Delta reservoirs. The result translates that a higher flow efficiency will result in a lower damage factor, while a lower flow efficiency will incur a higher damage factor. This also applies to the damage ratio analysis relative to flow efficiency. The higher the flow efficiency, the lower the damage ratio and vice versa.

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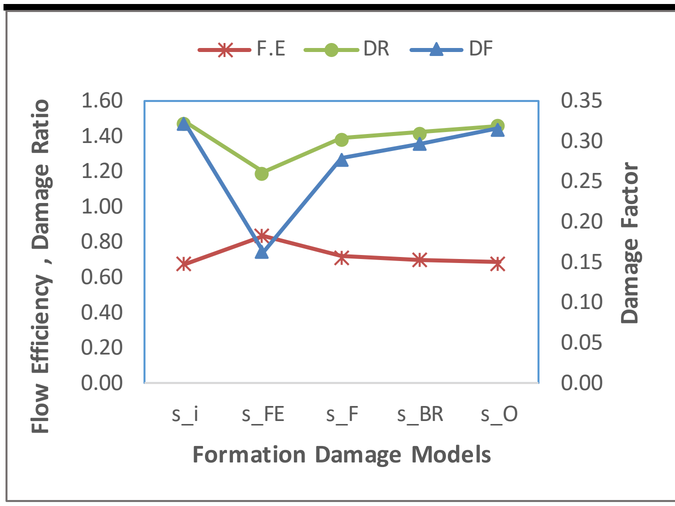

Fig.18: Variation in Flow Efficiency, Damage Ratio and Damage Factor for all Evaluated Damage Models in ND-1.

Figure 4.17 above shows that for reservoir ND-1, the buildup obtained reference skin model with a 67.73% flow efficiency had a corresponding damage factor and damage ratio of about 0.323 and 1.48 respectively. These values were close to that obtained from the Ozkan model which had damage factor and damage ratio o of 0.316 and 1.46 respectively with a corresponding flow efficiency of 68.37%. The B-R and Furui *et al* models followed successively in terms of DF and DR analysis.

Figure 4.18 shows that the Furui et al model proves a better alternative to the others in terms of Damage Factor and Damage ratio analysis as it tends to record a lesser deviation for the reference model for ND-2 reservoir. Having a damage factor of 0.373 and a damage ratio of 1.59 as against 0.405 damage ratio and 1.68 damage ratio for the buildup reference skin model.

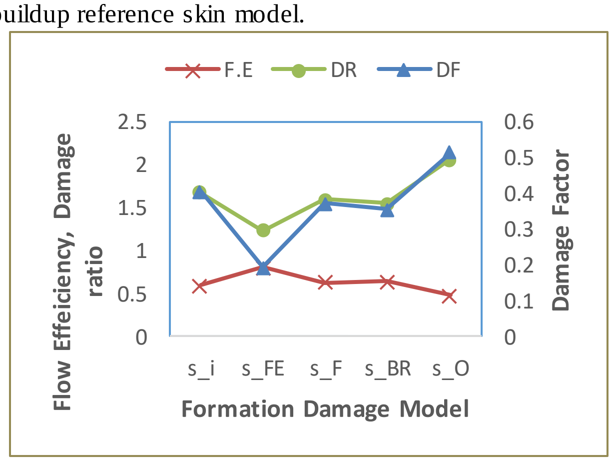

Fig.19: Variation in Flow Efficiency, Damage Ratio and Damage Factor with for all Evaluated Damage Models in ND-2.

A higher production rate of 800stb/day for the ND-3 reservoir revealed that the Ozkan and B-R models are a good alternative for formation damage magnitude evaluation in terms of damage intensity (damage factor and damage ratio) analysis.

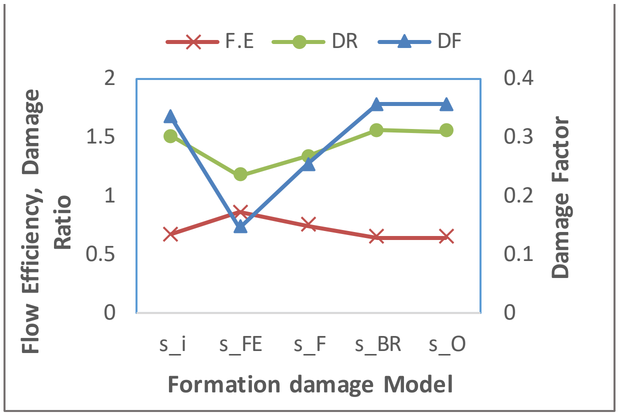

Fig.20: Variation in Flow Efficiency, Damage Ratio and Damage Factor for all Evaluated Damage Models in ND-3.

As shown in Figure 20 above, a damage factor of 0.36 and damage ratio 1.55 for both models could be said to match a 0.33 damage factor and a 1.50 damage factor deduction from the reference model. This goes a long way to ascertain than that at higher production rates, the Ozkan and B-R models mat be applicable provided parameter requirements are met for adequate simulation.

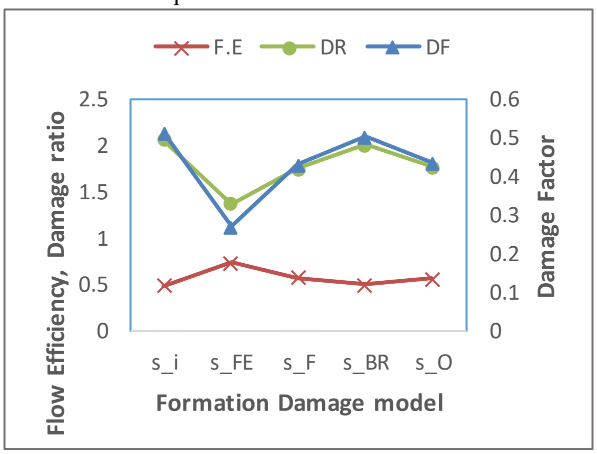

Fig.21: Variation in Flow Efficiency, Damage Ratio and Damage Factor for all Evaluated Damage Models in ND-4.

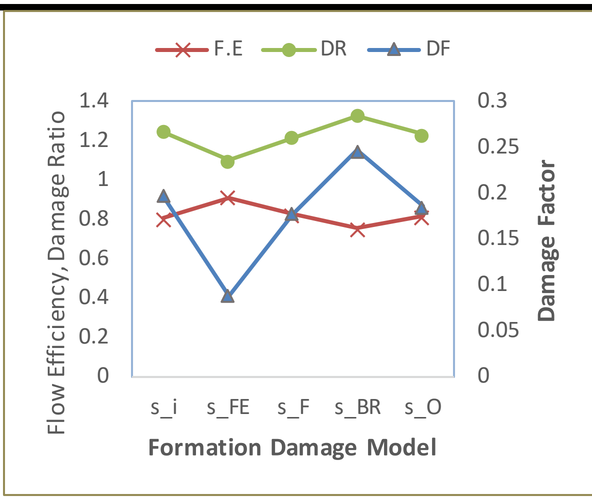

Fig.22: Variation in Flow Efficiency, Damage Ratio and Damage Factor withfor all Evaluated Damage Models in ND-5.

The low production rate reservoir of ND-4 revealed that the B-R model suites best for these reservoir conditions (petro physical, well and pressure transient properties) in terms of damage intensity as shown in Figure 21. Following the Behr & Raflee model in terms of applicability was that of Ozkan and then that of Furui *et al*.

The Offshore field having the highest production rate of 950 stb/day maintained that the models of Ozkan and Furui *et al* can the most applicable in terms of damage factor and damage ratio on parameter simulation. Both models having a lower deviation from the standard skin model.

IV. CONCLUSION

The models presented in this work provide predictive tools for quantitative evaluation of formation damage estimates in Niger Delta reservoirs. The theoretical agreement obtained between predictions by the evaluated models for this study and formation damage prediction from the empirical pressure buildup skin model has been thoroughly analyzed.

Skin usually referred to as formation damage is one of the major factors that influence a well or reservoir productivity. It tends to either promote or hamper production rates; it contributes greatly to pressure drop analysis in the entire production system, it influences well and reservoir deliverability and to some considerable extent, influences investment decisions and economic evaluation for candidate oil reservoirs particularly for unconsolidated sand reservoir systems like those of the Niger Delta.

In this work, one can clearly state that a comprehensive research and development study on the possible establishment of a unique formation damage model in Niger Delta area has been carried out. The numerical evaluation of these empirical models having incorporated their dependent variables yielded several series of damage responses. Critical evaluation on damage factor, damage ratio, flow efficiency, effective wellbore radius, and skin induced pressure drop analysis proved to be reliable analytical tools for the establishment of the unique model for the Niger Delta region.

Judging from the skin magnitude estimation standpoint, with reference to the buildup estimated skin model, the models were streamlined to only three during the selection procedure as the Frick and Economides model having skin as a function of only damaged radius, damaged permeability, wellbore radius and reservoir absolute permeability continuously underestimate skin values. This trend was observed for all five (5) reservoir cases leaving the models of Furui *et al*, Behr & Raflee and that of Ozkan to contend for the most suitable. The skin induced pressure drop analysis also translated the above mentioned case as the pressure drop due to skin is a function of the degree of damage to the formation around the wellbore vicinity. Flow efficiency and damage factor investigation translated the application of all streamlined three (Furui *et al*, Behr & Raflee and that of Ozkan) in a decreasing magnitude in the manner in which they appear for all five reservoirs.

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