Prediction of Scale Formation in Crude Oil Production along the Well-Bore As A Result of Incompatible Waters

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Abstract: **Formation and deposition of scale in porous media due to extensive use of seawater for oil displacement and pressure maintenance is a problem that results in production decline and loss of billions of dollars to the petroleum industry yearly. A variety of models are presently being used in the oil industry for predicting scaling tendency and average scale precipitation inside the reservoir.In this work, the prediction of scale formation was done by developing a computer program using Excel, and reservoir parameters data were imputed into the programmed models to obtain results which were used in plotting graph to analyse what happen along the wellbore during production as a result of injection of seawater which is likely to pose scaling threat to the wellbore at any time interval.Findings from the results and graphs obtained proved that the major threat to scale formation along the well bore (sulphate scale precisely) is pressure drop across the skin, the skin factor and the pore volume of water injected with respect to the amount of the sulphate scale precipitated.**

Key words: **well bore, scale formation, reservoir, pressure drop, porous media, models**

I. INTRODUCTION

Scale is the inorganic mineral deposited from brine (salt solution). Precipitation of scale can occur in the formation pores near the wellbore, thereby reducing formation porosity, permeability and hence impairing fluid flow in the formation. (Fadairo et al, 2009). Scale is normally deposited on processing equipment. When producing oil and gas, there will, in most cases, also be produced water, which contains dissolved salts. These salts may precipitate and they tend to deposit on surfaces. Scale, causes flow reduction or even blocking of pipes, valves and other equipment. Common types of scale during oil and gas production are $CaSO_4$,$SrSO_4$, $BaSO_4$ and $CaCO_3$. (Kristian, 2006).

Formation permeability damage due to oilfield scale precipitation and deposition in a porous media is a major problem during water flooding if the injected and formation water are incompatible. (Fadairo et al 2008)

Oil and gas production generally involveswater. This could be seawater, formation water and or injection water which, under some conditions, can lead to precipitations and deposition of mineral scale, such as calcium carbonate ($Caco_3$) and sulphates of barium, strontium, and calcium. This scaling can develop in the formation pores near well bore, (BaSo4) leadingto reduction in formation ($CaSo_4$) porosity and permeability; it can also block flow by forming thick lining on the production pipe and or coat and damage down holes completion equipment. , (Garba et al, 2004)

Information from the oil industry has indicated that many oil wells have suffered flow restriction because of scale deposition within the oil producing formation matrix and the down hole equipment, generally in primary, secondary and tertiary oil recovery operations as well as scale deposits in the surface production equipment. Scale formation in surface and subsurface has been recognized to be a major operational problem.

The deposition of the materials in the pore throat of the formation could prevent the normal natural flow of hydrocarbon towards the wellbore(Azeta, et al, 2012).

A supersaturated condition is essentially the main cause of scale formation and it occurs when a solution containing dissolved materials are present at a much higher concentrations than their equilibrium concentration. However, the amount and location of the scale formation can be influenced by several other factors but super saturation is the most prominent.

According to (Obot et al, 2015).scale formation is either influenced by temperature and/or pressure changes that are favourable to the precipitation of the mineral salts from formation waters, the mixture of incompatible waters during water flooding operations or pressure maintenance.

The major forms of oilfield scale include:

As brine (e.g., formation water) undergoes a temperature or pressure change during production, the solubility of some of the inorganic constituents will decrease and result in the salts precipitating. Scales formed under these conditions are generally calcium/magnesium carbonate scales. When two incompatible waters (such as formation water rich in calcium, strontium and barium and sea water rich in sulphate) are mixed, scales formed under these conditions are generally sulphate scales (ADENIYI et al, 2008).

To prevent production issues, it is possible to act upon two types of parameters: physical (pressure, temperature and rate) or chemical (composition of fluids) conditions. Fluids coming out of the reservoir have their own composition which can be easily modified by adding properly selected chemical additives to prevent issues described before, meanwhile physical parameters are mainly dependent on reservoir conditions and therefore nonchemical techniques can be applied to vary streams physical conditions (Danila, 2013).

Statoil has published their experience of scaling deposition during various operations (Danila, 2013).There is one other additional problem. During normal scale deposition (typically $BaSO4$), naturally occurring, radioactive isotopes can become tied up in the scale deposit. This result in deposits called 'Naturally Occurring Radioactive Material' (NORM), a highly regulated, hazardous substance. In this case, prevention of the normal scale deposit is the easiest and cheapest way to prevent the formation of NORM.

Much of the research previously, concern the prediction of productivity loss due to scale deposition. A recent paper byAdesina (Fadairo et al, 2007) presents an overview of a computer software which was developed to simulate formation damage of water flooded reservoir with possible incidence of mineral scale precipitation and deposition. It estimates oilfield scale saturation, instantaneous permeability and porosity, additional pressure drop and skin factor induced by oilfield scale during water flooding as a function of operational and reservoir / brine parameters.

This work used the modified Faruk Civian et al, model to predict the deposition of $BaS0_4$scale along crude oil production well bore. The significance of this work is the fact that waterflooding is the dominant among fluid injection methods of oil production and is responsible for the current high level of production rate of crude oil. However the inherent problem of this method is the formation damage, scale deposition and corrosion of well tubing. These problems are costing the oil industry a huge loss annually.

Therefore this work develops a predictive method of evaluating and controllingBarium Sulphate deposit on a well bore by using reservoir parameters and data to analyse the formation of this scale and to determine the conditions which accelerate this scale formation. The importance of the work is that it tends to alert the oil field operator when these conditions are significant so as to prevent it. The oil operators prefer a preventive method such as this because prevention is technically and economically more effective than dissolution once scale has formed. Scale Prediction aids scale management (Merdhah, et al 2008).

Fig 1. Scale formation in tubing (sandengen, 2006)

II. METHODOLOGY

The key factors that govern the rate of scale build up and magnitude of flow impairment are the following;

- The fractional change in the amount of solid salts that occupy the pore spaces at reservoir conditions.
- Pressure drop which causes reduction in the solubility of solid salt in the reservoir..
- The degree of flow impairment by the deposited scale, which influences the permeability of the fluid phase. The permeability will be influenced by the location of the deposits.

III. MODEL ASSUMPTION

The analytical expressions derived in this study are based on the following fundamental and general assumptions:

1. Solid precipitates are uniformly suspended in an incompressible fluid
2. The porous medium is homogeneous, isothermal and isotropic
3. The porous media contain a large number of pore spaces, which are interconnected by pore throat whose sizes are log- normally distributed
4. The interaction forces between the medium and precipitated solid minerals are negligible.

Several models have been established to predict scale formation (build up) around the well-bore. Some researchers have done some modifications on some of these models

However, this paper was based on the model presented by. Fadairo et al, (2009) and was used in this work. The permeability damage coefficient (k) is given by

$$k = k_o[1 - \lambda_{\Phi.}Ss(1 - S_{wi})]^{3.0} \text{.................................. (1)}$$

where k_o is initial permeability,.$\lambda_\emptyset$is porosity damage coefficient and S_{wi} is connate water saturation.

Computer program (in Excel) was developed to simulate formation damage of water flooded reservoir with possible presence of mineral scale precipitation and deposition. The computer program was used to evaluate the permeability, porosity, additional pressure drop, skin factor and change in porosity as a function of reservoir brine parameter.

The reservoir data of Fadairo et al, 2010 in the Table1 below was used as input into the model.

Table 1: Fluid and reservoir base properties

Pay thickness (h)	26m
Initial permeability	0.5922E-13m²(60mD)
Initial porosity	0.05
Reservoir pressure	36600kpa
Bottom hole pressure	22060kpa
Reservoir temperature	353K(80°C)
Brine formation volume factor	1.7
Brine viscosity	0.0007pa.s
Hydrocarbon viscosity	0.003
Connate water saturation	0.2

Table 2: Amount of $BaSO_4$ precipitated (Haarberg et al, 1992)

Pore Volume Of Seawater Injected (%)	$BaSO_4$ precipitated (g/m3)
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

Radial distance covered by oil field scale, flow rate and productiontime was chosen arbitrarily, and according to the range given by Fadairo, (201 i.e.,between 0- 5m,

Table 3: Radial distance and production time data.

The parameters are shown below;

Radial Distance, Rs(M)	Flow Rate Q(M3/Sec)	Production Time (Sec)
0.10	2.315E-4	86400
0.60	3.009E-4	208800
1.20	4.514E-4	108000
1.70	5.787E-4	216000
2.00	6.366E-4	288000
2.20	6.944E-4	252000
2.60	7.176E-4	360000
2.90	7.986E-4	396000
3.00	8.333E-4	306000
3.50	8.681E-4	540000
3.98	9.259E-4	522000

In pressure transient analysis, the wellbore is assumed to be cylindrical and has a specific radius called the wellbore radius as shown in Figure 2 below.

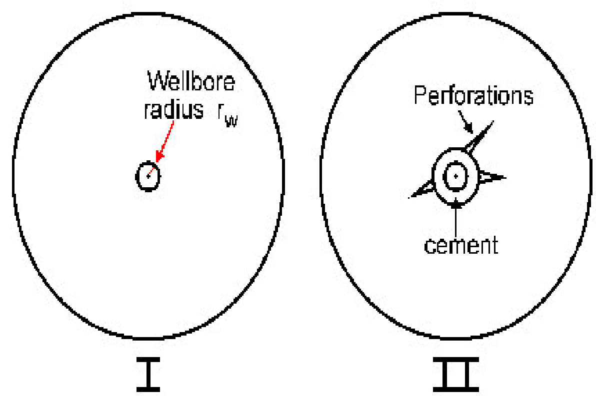


Fig. 2: Well Bore Radius

This radius was used to determine the sand face area (2r w h) which representedthe area through which all the produced reservoir fluids must flow. In real life, the area of contact between the wellbore and the formation is rarely cylindrical as seen above in Figure (2II) It depends on the perforations (density, phasing, effectiveness, etc.) and is also affected by the type of perforating gun, casing, cement, etc. Thus, a true wellbore radius does not exist (except for open hole completions) A reasonable value to use can be the drill bit radius, or the outside diameter of the casing. The default value used in the software is 0.3 ft. (0.091 m).

3.2 Model Analysis

Theory of the oil field scale build up around the well-bore

Consider the radial flow at constant rate q, and saturation with solid state particle at a location r, from the well bore. Based on the existing thermodynamic model, the theoretical model required for describing the fraction of oil field scales that occupies pore spaces and their corresponding formation damage, skin factor, additional pressure drop across the skin have been reported respectively as follows.

3.2.1 Scale Saturation Model

Assuming an idealized flow equation, Fadairo et al (2010) expressed sulphate scale saturation around the well bore as

$$S_S = \frac{q2\left[\frac{dc}{dp}\right].B.\mu.t.\lambda k}{4\pi 2.r2.h2.\phi_{\circ}.\lambda\varphi.k_{\circ}.\rho(1-swi)} / \text{ .... (2)}$$

Where λ_k and λ_φ define as formation damage coefficient and porosity damage coefficient respectively;

$$\lambda_k = \exp\,(3.k_{dep}.c.t) \text{............................... (3)}$$

$$\lambda\varphi = \exp\,(-k_{dep}.c.t) \text{........................ (4)}$$

Therefore, the change in concentration per unit pressure drop for minerals can be obtained in volume per volume per unit pressure drop (m^3/m^3/psi) (Fadairo 2009), as

$$\left[\frac{dc}{dp}\right] = \frac{(cp)-C(l)}{\rho.\Delta P} \text{................................ (5)}$$

3.2.2Scale Induced Permeability Damage

Fadairo et al model to handle permeability damage and porosity damage induced by sulphate scale at different radial distances from the well bore is as follows:

Permeability damage model:

$$k = k_{\circ}\,[1 - \lambda_{\varphi} S_S(1 - S_{wi})] \text{ ... ...(6)}$$

Porosity damage model:

$$\phi = \phi_{\circ}[1 - \boldsymbol{\lambda}_{\varphi} s_s(1 - S_{wi}) \text{ ... ...(7)}$$

3.4Skin Factor Model Formulation

Formation damage due to oil field scale deposition during water flood results to positive skin effect around the well bore. The skin factor is a dimensionless variable used in petroleum field calculation to estimate the magnitude of skin effect or degree of damage in formation. The skin factor can be expressed conventionally as; (Fadairo et al, 2010).

$$s = \left[\frac{k_{\circ}}{k}\right] \ln \frac{rs}{rw} \text{ ... ...(8)}$$

Fadairo et al expressed the effect of scale build up on skin factor and corresponding additional pressure across the skin at different pore volumes of sea water injected and different operational and reservoir/brine parameters in vertical well.

The oilfield scale induced skin factor can be expressed as;

$$Sv = \{[1\text{-}\lambda\varphi.\ Ss.(1 - Swi)]^{-3.0} - 1\} \ln \frac{rs}{rw} \text{....................... (9)}$$

The additional pressure drop across the oilfield scale induced skin factor can be express as;

$$\Delta P_{Sw} = \frac{q.B.\mu}{2\pi.h.k_{\circ}} \{[1 - \boldsymbol{\lambda}_{\varphi}.S_S(1 - S_{wi})]^{-3} - 1\} \ln \frac{rs}{rw} \text{........................ (10)}$$

Change in porosity can be obtained as;

$$\phi_d = \frac{q2.\left[\frac{dc}{dp}\right]..B.\mu.t.\lambda k}{4\pi 2.rs2.h2.k_{\circ}.\rho.\phi_{\circ}} \text{.. (11)}$$

3.5Operation of the Computer Programme

The computer program can be run by clicking on (SULPHATE SCALE PREDICTION MODEL).

On opening the program, the calculated result are presented in tabular form and the parameters can be change or varied to obtain other value as required based on the data available. The programme is capable of plotting graph directly on variation of the reservoir parameters.

Immediately the parameters are changed, the graph is changed as well and the programme was developed in such a manner that at any time the graphs can be added if one wants to plot other results.

IV. RESULT AND DISCUSSION

Result:

Table 4: showing the results obtained from the simulationΔ

Pdc	$Pem.dc$	Ss	Sv	ΔPsv	ϕd	k
1.00	1.00E+00	2.00E-28	0.00	0.00	2.50E-28	5.92E-14
5.17E-09	7.22E+24	2.12E-01	4.96E-09	1.84E-04	4.62E-26	5.92E-14
1.30E-06	4.56E+17	6.23E-08	5.01E-13	2.78E-08	1.31E-13	5.92E-14
3.41E-14	2.52E+40	2.27E+16	-2.93E+00	-2.08E+05	1.13E-24	-9.41E-06
4.50E-17	1.10E+49	2.21E+25	-3.09E+00	-2.42E+05	2.52E-24	-2.01E+13
2.23E-14	9.04E+40	2.29E+17	-3.19E+00	-2.72E+05	3.17E-24	-2.71E-03
4.41E-16	1.17E+46	6.32E+22	-3.35E+00	-2.96E+05	6.76E-24	-4.38E+08
2.06E-15	1.14E+44	1.05E+21	-3.46E+00	-3.40E+05	1.15E-23	-2.04E+05
2.97E-09	3.83E+25	3.16E+02	7.87E-06	8.07E-01	1.08E-23	5.92E-14
1.96E-09	1.33E+26	2.86E+03	4.90E-05	5.23E+00	2.78E-23	5.92E-14
1.00	1.00E+00	3.06E-23	0.00	0.00	3.82E-23	5.92E-14

Where:pdc = Porosity damage coefficient

pem dc = permeability damage coefficient

Ss = saturation of sulphate scale presipitation

Sv = skin factor

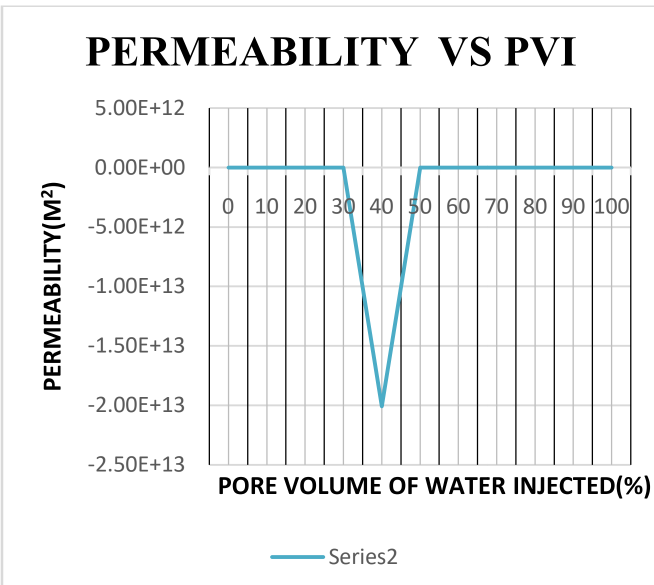
ΔPsv = aditional pressure drop across the skin

ϕd = change in porosity damage

k = permeability damage coefficient

4.1 Discussion of Result

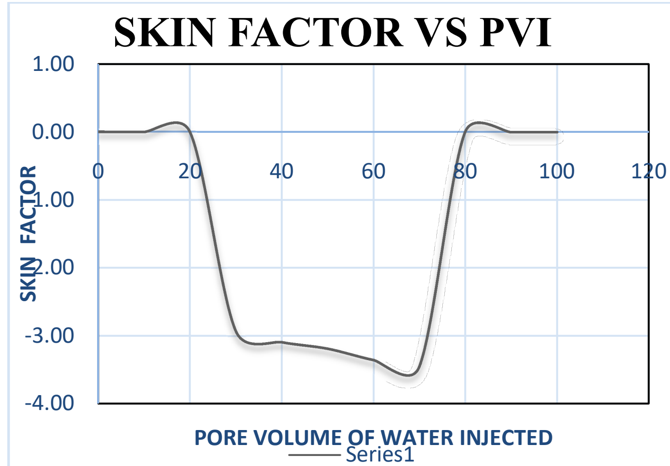
4.2.1 Permeability Damage:



Graph 1: permeability damage vs pore volume of water injected

From the result in Table 4, a plot of permeability against pore volume was made. This is presented in graph 1.0. This graph shows the permeability damage as water is injected into the reservoir.It can be seen that at low pore volume of water injected i.e.between the range 0 to 20%, permeability declined due to the precipitation of $BaSO_4$. Scale deposit is higher at lower pore volume of water injected. From the result presented in Table 4.0and graph above (graph 1) it can be seen also of how the additional pressure drop across the skin can increase the rate of permeability damage. At the range between 30 to 40% pore volume water injection; the permeability damage was at itshighest level as a result of the decrease in the additional pressure drop across the skin and the skin factor respectively.But at 50% to 100% seawater injection, the permeability was seen to gradually increase appreciably as soon as the additional pressure drops across the skin increased

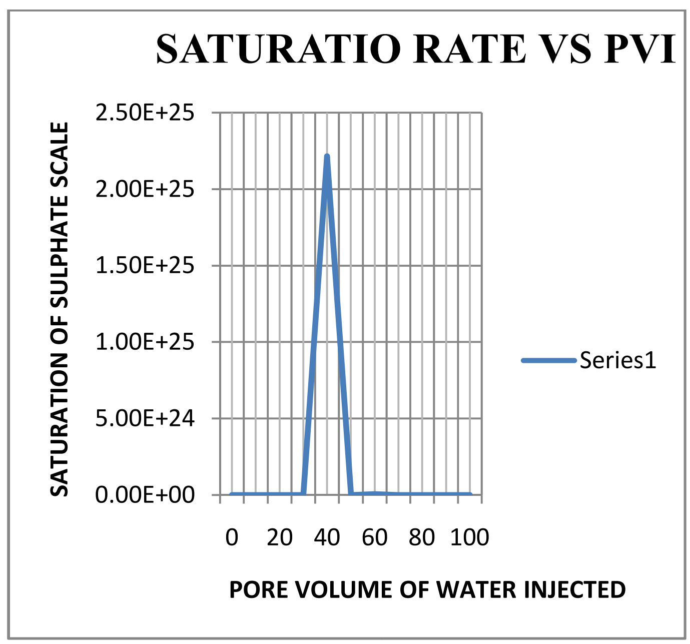
4.2.2 Skin Factor:



Graph 2: Skin Factor VS PVI.

At a range between 0% to10% PVI, the skin factorwas uniformly stable, but between 10% to 20 %, it increased due to increase in additional pressure drop across the skin Between 20% to 80% the skin factor was seen to reduce due to the decrease in pressure gradient,.it later maintained uniformity between 90 to 100% pore volume of water injected.

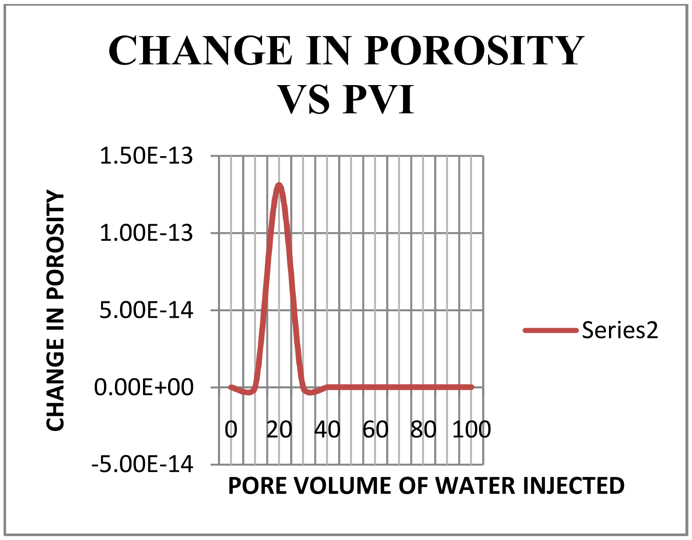
4.2.3 Saturation of Sulphate Scale:



Graph 3: Saturation of Sulphate Scale VS PVI

From Table 4.0, the graph of saturation of sulphate vs. PVI is presented, graph 3.0. From the graph, it can be seen that the saturation of sulphate scale was very high between 30 to 50%PVI, which could be the most likely point of partial or total blockage of the wellbore.

4.2.4 Change in Porosity Damage:



Graph 4: Change in Porosity Vs PVI

The graph of porosity damage as a result of injection of water is shown in graph 4.0. The graph shows how porosity is affected by addition of PVI. The change in porosity is noticed to be reducing between 10 to 30% PVI as a result of high concentration of BaSO4 precipitated, but this returned to normal between 30 to 100% PVI, as soon as the precipitation starts to reduce.

V. CONCLUSION

The following conclusions were drawn from the result above

1. The model developed by Fadairo et al,(2010), which is also known as the modified FarukCivian model used in the research work demonstrates the key factors that influence the rate of sulphate scale formation and permeability damage along the wellbore as a result of the mixing of incompatible water and the additional pressure drop across the skin during crude oil production. It also demonstrates how low pore volume of water injected can affect the saturation of Bariumsulphate, permeability, change in porosity, and skin factor respectively.
2. The permeability damage encountered does not only depend on the skin factor, the additional pressure drop across the skin but also on key operational and reservoir properties such as reservoir pressure, brine formation volume factor, connate water saturation etc.
3. At every given pore volume of seawater injected, the rate of damage for oil wells in water flooded reservoir due to sulphate scale deposition depends on oilfield solid scale saturation in the porous media.
4. At given water injected rate, the rate of scale build up around the wellbore can be significantly reduced by decreasing the pressure gradient near the wellbore.
5. The model program developed in this work can be used for diagnosis; evaluation and simulation of oil field scale build up rate and permeability damage caused during crude oil production. And it will also help to know when to carry out scale prevention measures.

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