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The Effects of Formation Damaged on Niger Delta Wells

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Abstract: Formation damage is one of the major challenges facing the oil and gas well. To tackle this problem, drilling and production engineers have come up with methods and ways to solve such a problem. In this work, several pressure build up data were gotten from unconsolidated oil well formation in the Niger delta part of Nigeria. The data were analytically analyzed for various reservoir parameters such as skin factor, permeability, flow rates, bottom whole pressure and their effects on production of oil and gas. The data obtained were plotted in excel software using Horner plot method. The results obtained for both wells showed a negative skin (-ve) meaning that the wells were not actually damaged. It also indicated that both wells have higher permabilities which resulted in higher flow rates.

Keywords: Formation Damage, Reservoir Parameters, Pressure Data, Production.

INTRODUCTION

When the productivity or injectivity of a well is lower than expected, it may be due to formation damage.Some mechanical factors such as limited peforation or partial penetration may also be a factor .The various factors involved in formation damage include external particles, invasion of fluid, formation fine migration, retention, permeability reduction, formation clay swelling, chemical precipitations, asphaltene deposition and rock deformation [1].Drilling mud pressure is usually maintained above formation pressure to prevent the reservoir fluid from flowing into the wellbore,which can cause well blowout conditions. As the drillbit penetrates a petroleum bearing formation,the drilling mud invades the formation due to the positive differential pressure between the mud and the reservoir fluids. Particles with diameter smaller than that of formation pores,enters the formation during mud spurts loss. They plug the formation around the wellbore and form an internal filter cake [2]. Particles with larger diameter than that of formation pores are either retained on the formation face initiating the build of an external filter cake,or are entrained in the circulating mud by the shear forces exerted by the mud.The formation of a low permeability mud cake on the entire sand face effectively prevents additional drilling muds solids from entering the formation,but does not stop the mud filltrate. However, this mud filtrate and other fine particles moves along with the fluids until they are captured at pore constrictions or deposited on other pore surface thereby causing formation damage [3] . One of the major operations during well completions is cementing.The primary cementing operations is to seal the annulus between the casing and the formation.A cement slurry is usually pumped into a well through the casing in order to diplaces the drilling fluid from the pipe into the annulus.The cement filtrate invades the formation similarly to the mud filtrate,causing formation damage.Various studies indicates that the cement slurry can cause formation damage due to interactions of the cement filtrate with formation fluids or minerals [4]. A popular method to treat a damaged is to inject acids, such as hydrochloric and hydrofluoric acids into the near formation wellbore. Although the objective of acid stimulation is to remove damage and improve well productivity, acid treatments do not always increase well productivity. Occasionally, they may even reduce productivity [5]. A solid understanding of damage mechanisms, formation mineralogy and brine chemistry is necessary to obtain optimum results for acid treatments. For example, hydrofluoric acid can react with the calcium compound present in the formation, which can result in formation of insoluble precipitates. During acid treatment, some minerals are dissolved that may re-precipitate later. Fine particles loosely attached to pore surfaces can be mobilized during the acid treatment. Excessive acid treatment can dissolve the cementing materials of the formation, which will cause pore collapse and formation deconsolidation [6]. In an oil well, skin factor is one of the indicators that tell whether a formation is damage or not. [7] defined skin factor as the fraction of the total pressure in the system that is consumed by flow through the basic rock. [8] defined skin factor as a measure of damage around the wellbore due to completion and drilling practices. [9] had it that wellbore damage is one of the major problems that petroleum engineers try to avoid during drilling, completion and well production. In a normal situation, an undamaged formation has a skin factor of zero while a damage formation has a skin factor more than zero. Based on this, it has become important to study the conditions that caused a change in the value of permeability of a well. Skin is the alteration of the formation permeability around the producing zone, it occurs in a few inches around the wellbore. The degree of skin in the formation is called skin factor. Skin due to damage is a measure of the amount of damage or improvement to the formation near the wellbore. Damage can be caused by drilling fluids, migration of fines, invasion, etc. and results in a reduced permeability near the wellbore and a positive skin. The magnitude of the positive skin effect is generally 0 to 50 but can be as high

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as 200 [10]. Improvement can be accomplished by acidizing or fracturing which results in an increased effective permeability near the wellbore and a negative skin. The magnitude of the negative skin effect is generally 0 to -5. In some cases it can be as low as -6 or -7 which generally implies the presence of reservoir heterogeneities such as natural fractures or formation permeability contrasts, rather than stimulation effects due to wellbore completion operations. The skin effect is a dimensionless quantity and is defined as the difference between the actual and the ideal dimensionless pressure drop in a reservoir or pressure drop due to skin (Dp_{skin}).

MATERIALS AND METHOD

Data Requirement

- Bottom hole pressure, Pws, Psi
- Average time, hrs
- Permeability (k)
- Flow rates (bbl/day)
- Porosity (ø)
- SEMI LOG GRAPH/PAPER\

Procedures

This research work analytically evaluates the productivity and permeability of two wells. To achieve this, a bottom hole pressure test data was obtained, and the following procedures were undertaken:
The well production and reservoir data as stated in the material requirement was obtained using the Horner approximations, (tp +Δt)/Δt representing the flowing time before the well was shut in for both wells plotted. After which, the BHP vs. (tp + Δt/ Δt) was plotted on a semi log plot.

$$s = 1.151[\frac{P_{1hr-}pwf(\Delta t = 0)}{m} - \log\frac{k}{\phi\mu c_t r_w^2} + 3.23]$$

This was achieved by the use of a soft ware tool called EXCEL. Plotting the pressure build up data and the time change data on the vertical and horizontal axis respectively. An analysis was made on the result for skin damage based on the plotted graph and with focus on the permeability (K), Pi (initial reservoir pressure) and also the flow rate **(q)**. The analysis for the various parameters stated above was done using the following equations.

EQUATIONS UNDER CONSIDERATIONS

$$k = \frac{162.6qB\mu}{mh} \quad (1)$$

$$m = \frac{162.6q_O B_O \mu_O}{kh} \quad (2)$$

$$Pws = Pi - \frac{162.6B\mu q}{kh}\left[\log\frac{t_p + \Delta t}{\Delta t}\right] \quad (3)$$

$$s = 1.151[\frac{P_{1hr-}pwf(\Delta t = 0)}{m} - \log\frac{k}{\phi\mu c_t r_w^2} + 3.23]$$

RESULTS AND DISCUSSION

TABLE 1: PRODUCTION DATA FOR WELL A

T Time	Pressure	Time	Pressure
0:00:00	3935.98	0:01:31	4933.1
0:00:02	4923.98	0:01:42	4933.58
0:00:05	4924.46	0:01:55	4934.06
0:00:08	4924.94	0:02:09	4934.54
0:00:11	4925.42	0:02:24	4935.02
0:00:14	4925.9	0:02:42	4935.51
0:00:17	4926.38	0:03:02	4936.4
0:00:20	4926.86	0:03:24	4936.77
0:00:22	4927.34	0:03:49	4937.1
0:00:25	4927.82	0:00:00	4937.4
0:00:28	4928.3	0:00:00	4937.67
0:00:32	4928.78	0:00:00	4938.07
0:00:36	4929.26	0:06:03	4938.12
0:00:40	4929.74	0:06:48	4938.31
0:00:45	4930.22	0:07:38	4938.48
0:00:51	4930.7	0:08:33	4938.64
0:00:57	4931.18	0:09:36	4938.79
0:01:04	4931.66	0:10:47	4938.92
0:01:12	4932.14	0:12:05	4939.05
0:01:21	4932.62	0:13:34	4939.17

TABLE 2: RESERVOIR PROPERTIES FOR WELL A

q	1000STB/day(assumed)
B	1.125rb/STB
m	300psi/cycle
k	7.3md
ø	0.25(assumed)
µ	0.6cp(assumed)
Ct	0.000002psi(assumed)
rw	0.5(assumed)
h	50ft(assumed)
P1hr	4940psi
Pwf Δt=0	3935.8psi

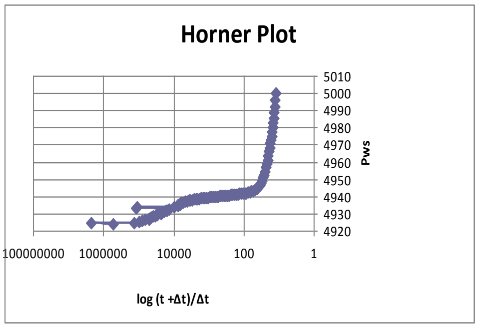

Fig.2 Horner plot from well A

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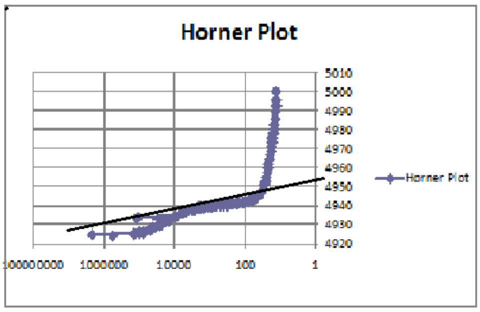

fig 4 Horner plot for well A (showing line of slope)

The above slope for our Horner plot well A was gotten by using equation (2) which is represented thus:

$$m = \frac{162.6 q_O B_O \mu_O}{kh}$$

From the graph identifying the correct straight line portion of the curve and then determining the slope **m** to give:
m = 300 psi/cycle (from the straight line traced to the time data)

CHANGES IN PERMEABILITY

Permeability, regarded as the flow ability of the well was calculated thus: using equation (1) having gotten our slope, m.

$$k = \frac{162.6 qB\mu}{mh}$$

However, because the buildup in wellbore pressure will generally follow some definite trend, with the above equation it is possible to analyze the pressure buildup and then determine our average permeability.
To achieve that the following reservoir data were available:
μ = 0.6cp, B =1.125rb/STB, h = 50ft, q =1000STB/d
Substituting the values into equation (10)

$$K = \frac{(162.6).(1000).(1.125).(0.6)}{(300).(50)}$$

K = 7.3md

EFFECT OF SKIN

To check for the effect of skin which equation (4) which represents our skin equation) was applied
From our plot, **Pwf** after 1hour, **4940** traced from the straight line portion of the curve.
Where Pwf (Δt = 0) = observed flowing bottom-hole pressure immediately before shut-in
m = slope of the Horner plot
k = permeability, md
Substituting the reservoir data into the above (skin) equation
P1hr =4940, Pwf (Δt = 0) = 3935.98 Psi
m =300psi/cycle, k = 7.3md, ϕ =0.25, μ = 0.6cp

$c_t = 20 \times 10^{-6}$, $r_w = 0.5$ Substituting the values into the equation, the skin was gotten S = -1.6773359; negative skin

PLOT ANALYSIS FOR WELL B

TABLE 3: RESERVOIR PROPERTIES FOR WELL B

Q	123STB/day(assumed)
B	1.22rb/STB(assumed)
M	300psi/cycle
K	1.52md
Ø	0.20(assumed)
μ	1.0cp(assumed)
Ct	0.0000018psi(assumed)
Rw	0.3(assumed)
H	20ft(assumed)
P1hr	3244.1psi
Pwf Δt=0	3183.76psi

TABLE 4: PRODUCTION DATA FOR WELL B

time,t	Pressure	Δp	tp +Δt	(tp +Δt)/Δt
0	3183.76	-	1000	-
0.0001	3184.28	0.52	1000	10000001
0.0002	3187.77	3.49	1000	5000001
0.0245	3203.3	15.53	1000.025	40817.33
0.012	3221.21	17.91	1000.012	83334.33
0.0275	3235.69	14.48	1000.028	36364.64
0.0557	3240.73	5.04	1000.056	17954.32
0.0888	3241.3	0.57	1000.089	11262.26
0.1776	3242.6	1.3	1000.178	5631.631
0.3774	3243.37	0.77	1000.377	2650.709
0.5376	3243.74	0.37	1000.538	1861.119
0.7776	3244.1	0.36	1000.778	1287.008

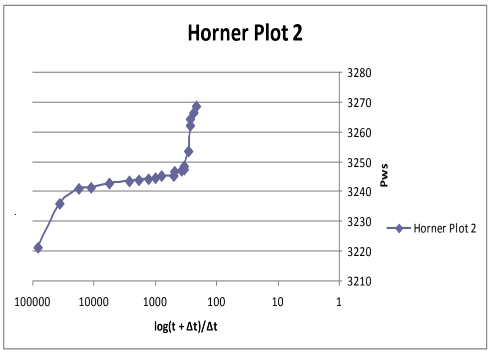

Fig.3 Horner plot for well B

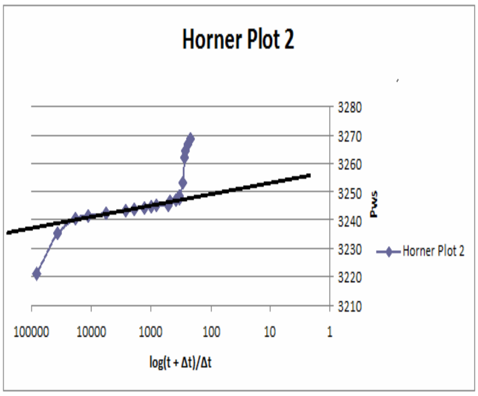

Fig 4 Horner plo t for well B showing the line of slope

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SLOPE OF THE CURVE FOR WELL B

$$m = \frac{162.6 q_O B_O \mu_O}{kh}$$

Slope, m: 800psi/cycle (from the straight line traced to the time data)

CHANGES IN PERMEABILITY

Applying the permeability equation:

$$k = \frac{162.6 q B \mu}{mh}$$

The following reservoir data was applied to calculate for permeability

$$K = \frac{162.6 \times 123 \times 1.22}{800 \times 20}$$

K = 1.52md

SKIN EFFECT

Skin equation was applied to calculate for skin with the reservoirs data or parameters:

$$S = 1.151\left[\frac{P1hr - pwf(\Delta t = 0)}{m} - \log\frac{k}{\phi \mu c_t r_w^{\;2}} + 3.23\right]$$

P1hr = 3183.76
m = 800psi/cycle
k =1.52md
ø = 0.20
μ=1cp
c_t =0.0000018
r_w = 0.3

Substituting the values into the equation, the skin was gotten

S = -5.9985; negative skin

DISCUSSION

In the procedures of this work, several pressure data were put under analysis through graphical representation in a semi log plot. Generally, the pressure build up curve was obtained by measuring the bottom hole pressure in a flowing well together with the subsequent pressure increase during a period of sufficient duration following the shutting in, and it is assumed that the well has been producing at a constant rate, q, during a considerable time,t. However, pressure increase upon closing in is recorded as a function of closed in time and only those pressure increases are used after the effects of storage in casing and tubing have died down. Amongst other things as regards this work, estimation was made for several reservoir parameters such as porosity, permeability and other various parameters. An estimation was made to see if there was any improvement around the wellbore or if damage actually occurred due to several drilling and completion practices. Estimation was also made to see or determine reservoir sand continuity.

However, the data given for both wells were further applied in the determination of skin, productivity index and flowing pressure.

Traditionally, as with every plot there was some drawbacks as regards scales and several lines appearing and the little confusion as which line to use. This challenge was observed especially looking at our first well Horner plot, it was little bit difficult picking our slope, but the straight line portion was picked so as to get a fitting slope. This was not really seen in the second plot because it was easy picking up our slope though a higher slope figure was seen for both wells. In the analysis of both wells for skin as to check for formation damage, the pressure build up data was analyzed with the help of the Horner plot . This was made possible with various equations stated in the procedures of this work (equation 1, 2,3 and 4). Based on the results gotten for both wells, plotting time against pressure(Pws),it was seen that well A and well B both had a negative skin and based on our interpretation for skin it means that both wells do have permeability higher than expected and hence a higher flow rate will result for both wells.

CONCLUSION

Formation damage as we all know is not a welcome situation or condition in the oil and gas industry. From our Horner plot analysis, we obtained a negative skin for both wells meaning that the well is yet to be damaged since our results did not come out positive for skin. Also as stated earlier, the magnitude of the positive skin effect is generally 0 to 50 but can be as high as 200. Improvement can be accomplished by acidizing or fracturing and results in an increased effective permeability near the wellbore and a negative skin. The magnitude of the negative skin effect is generally 0 to -5. In some cases it can be as low as -6 or -7 which generally implies the presence of reservoir heterogeneities such as natural fractures or formation permeability contrasts, rather than stimulation effects due to wellbore completion operations.

Hence, based on our results gotten through the use of Horner plot, it can be concluded that:

- Formation damages and skin effect has an adverse negative effect on wells in the oil and gas industry and should be checked early.
- Well A had a negative skin of -1.677359
- Well B also had a negative skin of -5.96682
- Well A had a higher permeability value than well B.

RECOMMENDATION

Decline in production, resistance to flow, loss of money, dead of wells and early abandonment of wells. Based on these issues, it is imperative; Horner plot was used in the analysis of the pressure build up data and hence fulfilling the objective as regards checking for damage in wells in the oil and gas industry and also used as an effective means in analyzing changes in permeability and so on.

Therefore as regards further projects involving well testing procedures, Horner plot will be a much effective and recommended means of analyzing such tests especially if it involves pressure build up.

NOMENCLATURE

B	=	oil formation volume factor
BHP	=	Bottom hole pressure
Ct	=	compressibility
h	=	height
K	=	permeability
M	=	slope
Pi	=	initial reservoir pressure
Pws	=	sand face pressure buildup
Pwf	=	bottom hole flowing pressure
ø	=	porosity
Q	=	flow rate
Rw	=	wellbore radius
S	=	skin factor
Tp	=	flowing time before shut in
µ	=	viscosity

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