Petroleum and Coal

Article Open Access

EFFECTIVE CANDIDATE SELECTION FOR STIMULATION: CASE STUDY OF THE NIGER DELTA OIL FIELD

K. K. Ihekoronye, I. V. Nwankwo*

Petroleum Engineering, Federal University of Technology Owerri, Nigeria

Received March 1, 2019; Accepted May 9, 2019

Abstract

Well tests are typically used to evaluate formation damage before and after workovers. Buildup test are the most commonly used transient analysis because less flow rate measurement uncertainties leading in more reliable results. In this research study, buildup tests were carried out in three wells A, B and C in the Niger Delta Oil Fields to determine their damage, permeability and skin. The result from the study shows that well A is damage having R-factor of 0.62. R-factor of >0.6 means the formation is damaged. However, well B and C have R-factor of 0.22 meaning the reservoir is undamaged. In addition, the skin factor in well A is 10.6 which indicate formation damage. On the other hand, well B and C have skin of (-1.45) which is a negative skin indicating that the reservoir is not damage. Furthermore, damage ratio due to skin is 2.68 in Well A as a result of skin while Well B and Well C is 0.82 which is very low to enhance well productivity. In conclusion, well A needs to be stimulated. While well B and C is stimulated.

***Keywords**: Well test; Horner plot; Build up; Skin; Formation damage.*

1. Introduction

Stimulation is often used to describe different operation that is carried out in an oil well to get optimum hydrocarbon productivity. This technique is very vital to encourage production of flow from the reservoir rocks to the wellbore since the hydrocarbons are located between the pores spaces of the reservoir rocks. As part of the reservoir characterization process and monitoring of reservoir conditions, the use of buildup test is well know, not only to determine the reservoir pressure but to evaluate well performance based on wellbore damage and effective permeability under varying flow conditions. Many of these tests are performed by shutting-in the well at the surface. This procedure results in the after flow effects, which is a sandstone flow for a short period of time, and it may be affected by fluid properties, petro physical properties and the pipe volume fluid, multiple phase segregation among others. Nitters *et al.* [1] presented a structured approach to stimulation candidate selection and treatment design. In their research, they isolated the real skin caused by formation damage from the portion of the total skin that can be removed by matrix treatment to the total skin. Afolabi *et al.* [2] also considered a candidate selection criterion that is based on minimum economic reserve. Jennings [3] in their research noted a candidate selection based on well capacity and concluded that well stimulation treatments in high-productivity wells allow better reservoir management through sustained productivity and more uniform reservoir depletion throughout the life of the well.

Thomas and Milne [4] noted that the candidate selection consists of identifying wells with low productivity relative to what they are capable of producing and also, the possible mechanical problems in these wells.

Buildup tests using downhole shut-in tools reduce substantially the wellbore storage effects [1]. Buildup test is conducted by producing a well at constant rate for some time, shutting the well in (usually at the surface (that is, q = 0), allowing the pressure to build up in the wellbore, and recording the down-hole pressure in the wellbore as a function of time. Martin [5] noted that candidate selection requires an accurate assessment of what a well can produce without impairment and the current productivity of the well. Onyekonwu [6] reported that skin and permeability of the formation could be determined through bottom hole pressure tests and other parameter that can help in well candidate stimulation. Gatlin *et al.* [7] wrote pressure build up method analysis is one of the quantitative ways of analyzing formation damage. Guoynes *et al.* [8] noted that one of the current typical issues related to hydraulic fracture is selection of candidate-wells. Moore and Ramakrishnan [9] wrote that it is possible to formulate a framework for the candidate-well selection for a certain field. It is possible to estimate the formation permeability and current drainage area pressure, and to characterize damage or stimulation and reservoir heterogeneity or boundaries frequently. Onyekonwu [6] noted that skin may not be the only yardstick for determining stimulation candidates. He also noted that R – factor is also a good yardstick for selecting stimulation candidate.

2. Objective of this study

The main objective of this study is aimed at implementing the principle of the R-factor, quantify and characterize the extent of damage using a pressure buildup analysis of these wells and hence achieve a good and effective candidate selection based on these parameters.

2.1. The possible sources of formation damage

1. Filter cake plugging; Drilling fluids serve to balance formation pressures while drilling to ensure wellbore stability. They also carry drilled cuttings to the surface and cool the bit. Filter cake plugging can result to problems like stuck pipe, differential sticking and large filtrate loss.
2. Fines in sandstone: Particle invasion and fines migration are among the major factors causing formation damage. Field studies and laboratory experiments have indicated that the fines cause permeability reduction [10].
3. Scale formation: The formation of mineral scale associated with the production of hydrocarbon is a concern in oilfield operation [11]. Depending on the nature of the scale and the fluid composition, the deposition can take place within the reservoir which causes formation damage
4. Polymer precipitation; polymers tend to reside in formation due to precipitation, and adsorption [11].

3. Methodology

3.1. Factor to consider when selecting stimulation candidate

3.1.1. Productivity index

Productivity index (PI or J) is a measure of the capability of a reservoir to deliver fluids to the bottom of a wellbore for production. It defines the relationship between the surface production rate and the pressure drop (drawdown) across the reservoir. Expressed mathematically, it is given as:

$$PI = J = \frac{q_s}{p_e - P_{wf}} \quad \ldots \tag{1}$$

For steady state flow of incompressible fluid

$$PI = J = \frac{q_s}{p_e - P_{wf}} = \frac{7.08kh}{UBIn\frac{r_e}{r_w}} \tag{2}$$

For semi steady state

$$PI = \frac{q_s}{P - P_{wf}} = \frac{7.08kh}{UB\left[In\frac{r_e}{r_w} - \frac{3}{4}\right]} \text{ for average pressure} \tag{3}$$

$$PI = \frac{q_s}{P_e - P_{wf}} = \frac{7.08kh}{UB\left[In\frac{r_e}{r_w} - \frac{1}{2}\right]} \text{ for normal pressure} \tag{4}$$

3.1.2. Productivity ratio

$PR = \frac{Avearage\ actual\ permeability}{Average\ undamged\ permeability}$

S> 0=damaged formation (PR<1) S=0=No damage (PR=1) S<0=Enhanced production (PR>1)

3.1.3. Skin factor

The skin factor does affect the shape of the pressure buildup data. In fact, an early-time deviation from the straight line can be caused by skin factor as well as by wellbore storage. Positive skin factor indicates a flow restriction,

For s>0 there is formation damage. On the other hand, if s<0 (-ve) there is enhancement or stimulation that is., wellbore damage. A negative skin factor indicates stimulation. To calculate skin factor, s from the data available in the idealized pressure buildup test. At the instant a well is shut-in, the flowing BHP, P_{wf} is

At shut-in time Δt is the buildup test

$$P_{wf} = P_i + m\left[log\left(\frac{tp+\Delta t}{\Delta t}\right)\right] \quad (5)$$

$$S = 1.151\left(\frac{P_{ws}-P_{wf}}{m}\right) + 1.151\ log\left(\frac{1688\theta U_0 C_t\ r^2{}_w}{K\Delta t}\right) + 1.151\ \log\left(\frac{tp+\Delta t}{\Delta t}\right) \ldots \quad (6)$$

Before shut-in at $\Delta t = 0$. With these simplifications, the skin factor is

$$S = 1.151\left[\frac{p_{1hr}-p_{wf}(\Delta t=0)}{m} - log\left(\frac{K}{\theta U_0 C_t r^2{}_w}\right) + 3.23\right] \ldots \quad (7)$$

3.1.4. Flow efficiency and damage ratio

The flow efficiency is defined as the ratio of the actual productivity index of a well to its productivity index if there were no skin (s — 0):

$$\text{flow efficiency} = F.E = \frac{J_{actual}}{j_{ideal}} \quad \text{since} \quad J_{actual} = \frac{q_0}{P-P_{wf}} \quad (8) \quad \text{and} \quad J_{ideal} = \frac{q_0}{P-P_{wf-(\Delta p)_{skin}}} \quad (9)$$

Therefore

$$F.E = \frac{P-p_{wf}-(\Delta p)_{skin}}{P-p_{wf}} \ldots \quad (10)$$

3.1.5. R-factor

R-factor > 0.6 damaged, while R- factor < 0.6 undamaged

3.2. Equations used for the well test analysis in this study

$$S = 1.151\left[\frac{p_{1hr}-p_{wf}(\Delta t=0)}{m} - log\left(\frac{K}{\theta U_0 C_t r^2{}_w}\right) + 3.23\right] \quad (11)$$

$$\frac{k_0\ h}{u_0} = \frac{162.6\ q_0\ B_0}{m} \ldots \quad (12)$$

$$k_0\ h = \frac{k_0}{u_0} \times u_0 \ \ldots \quad (13)$$

$$PI = \frac{q_s}{P-P_{wf}} \ldots \quad (14)$$

$$E = \frac{PI_{actual}}{PI_{ideal}} = \frac{P_R - P_{wf} - \Delta P_S}{P_e - P_{wf}} \quad (15)$$

$$P_{ws} = P_i - \frac{162.6\ qB\ U}{K_h}\ log\ \frac{t_p+\Delta t}{\Delta t}. \quad (16)$$

$$r_i = \left(\frac{K_0\ t}{948\ \theta\ u_0\ c_t}\right)^{1/2} \ldots \quad (17)$$

$$\Delta P_s = 141.2 = \frac{q_0\ u_0\ B_0}{K_0\ h} \times S \quad (18)$$

$$R - factor = \frac{141.2\ \frac{Q_0\ B_0\ U_0}{K_0\ h} \times S}{P - P_{ws}} \quad (19)$$

3.3. Effective candidate selection procedure

1. Monitor the trend in performance of the well over time and establish a persistent decline that is different from the expected natural decline of the well.
2. Shut in the well and perform a detailed build up test.
3. Analyze the build up test using Horner's procedure.
4. Evaluate the reservoir parameters required for quantifying damage (example, skin, pressure drop due to skin, K-factor and check whether value is up to 0.6.
5. If the condition is satisfied, the well is qualified as a stimulation candidate

Quantifying formation damage –well test analysis approach for Well A

Table 1 Reservoir rock and fluid properties for Well A

Parameter	Values	Parameter	values
Flow rate (B/d)	725	Oil formation volume factor	1.174
Porosity (%)	0.26	Area (acres)	40
Total compressibility (psi)	0.0000189	Pws $(\Delta t = 0)\ psi$	3409.37
Height (ft)	88.0	Dimensional time (hrs)	24
Viscosity (cP)	3.0	Wellbore radius (ft)	0.51

Table 2. Data used for the Horner plot analysis for WELL A

∆t (hrs)	Pws (psi)	(td+ t)/∆t	∆t (hrs)	Pws (psi)	(td+ t)/∆t
0	3409.37	0	0.1104	3535.22	218.39
0.0024	3419.23	10001.00	0.1272	3538.85	189.68
0.0048	3429.09	5001.00	0.1416	3541.71	170.49
0.0096	3437.14	2501.00	0.1632	3544.04	148.06
0.0144	3446.74	1667.67	0.2208	3546.12	109.69
0.0192	3454.78	1251.00	0.3432	3548.71	70.93
0.0240	3464.90	1001.00	0.6552	3548.97	37.63
0.0288	3473.72	834.33	0.0032	3549.23	24.92
0.0336	3481.25	715.28	1.3632	3549.49	18.61
0.0384	3486.70	626.00	1.7232	3549.75	14.92
0.0456	3496.56	527.32	2.0832	3550.01	12.52
0.0508	3503.82	473.44	2.4480	3550.27	10.80
0.0624	3510.57	385.62	2.8032	3551.05	9.56
0.0720	3518.87	334.33	3.1632	3551.53	8.58
0.0816	3525.10	295.11	3.5328	3551.57	7.79
0.0888	3527.95	271.27	3.8880	3551.82	7.17
0.0984	3530.55	244.90			

Quantifying formation damage –well test analysis approach for Well B

Table 3. Reservoir rock and fluid properties for WELL B

Parameter	Values	Parameter	Values
Flow rate (B/d)	984	Oil formation volume factor	1.362
Porosity (%)	0.25	Area (acres)	40
Total compressibility (psi)	0.0000173	Pws $(\Delta t = 0)\ psi$	3679.18
Height (ft)	30.0	Dimensional time (hrs)	24
Viscosity (cP)	0.53	Wellbore radius (ft)	0.4

Table 4 Data used for the Horner plot analysis for WELL B

∆t (hrs)	Pws (psi)	(td+ t)/∆t	∆t (hrs)	Pws (psi)	(td+ t)/∆t
0	3679.18	0	1.8083	3761.87	14.27
0.006	3694.38	4001.00	2.1683	3763.09	12.06
0.0083	3714.14	2892.56	2.5308	3764.60	10.48
0.0108	3732.69	2223.22	2.8908	3764.91	9.30
0.0132	3744.24	1819.18	3.2508	3766.13	8.38
0.0157	3747.58	1529.66	3.6108	3767.04	7.65

∆t (hrs)	Pws (psi)	(td+ t)/∆t	∆t (hrs)	Pws (psi)	(td+ t)/∆t
0.018	3748.80	1334.33	3.9708	3767.04	7.04
0.0203	3750.02	1183.26	4.326	3767.95	6.55
0.0252	3751.54	953.38	4.86	3768.87	5.94
0.126	3755.79	191.47	5.053	3769.08	5.74
0.3708	3757.72	65.72	5.410	3771.3	5.44
0.738	3758.53	33.52	5.768	3772.21	5.16
1.0932	3759.14	22.95	6.044	3772.82	4.97
1.4508	3760.05	17.54			

Quantifying formation damage –well test Analysis approach for WELL C

Table 5. Reservoir rock and fluid properties for WELL C

Parameter	Values	Parameter	Values
Flow rate (B/d)	984	Oil formation volume factor	1.362
Porosity (%)	0.24	Area (acres)	40
Total compressibility (psi)	0.0000173	Pws $(\Delta t = 0)\, psi$	3679.18
Height (ft)	30.0	Dimensional time (hrs)	24
Viscosity (cP)	0.55	Wellbore radius (ft)	0.4

Table 6. Data used for the Horner plot analysis for WELL C

∆t (hrs)	Pws (psi)	(td+ t)/∆t	∆t (hrs)	Pws (psi)	(td+ t)/∆t
0	3679.18	0	1.8083	3761.87	14.272
0.006	3694.38	4001.00	2.1683	3763.09	12.069
0.0083	3714.14	2892.566	2.5308	3764.60	10.48
0.0108	3732.69	2223.222	2.8908	3764.91	9.302
0.0132	3744.24	1819.182	3.2508	3766.13	8.385
0.0157	3747.58	1529.70	3.6108	3767.04	7.65
0.018	3748.80	1334.333	3.9708	3767.04	7.044
0.0203	3750.02	1183.266	4.326	3767.95	6.60
0.0252	3751.54	953.381	4.86	3768.87	5.94
0.126	3755.79	191.476	5.053	3769.08	5.80
0.3708	3757.72	65.725	5.410	3771.3	5.44
0.73	3758.53	33.52	5.768	3772.21	5.20
1.0932	3759.14	22.954	6.044	3772.82	4.97
1.4508	3760.05	17.543			

4. Result presentation well test analysis for WELL A, B and C

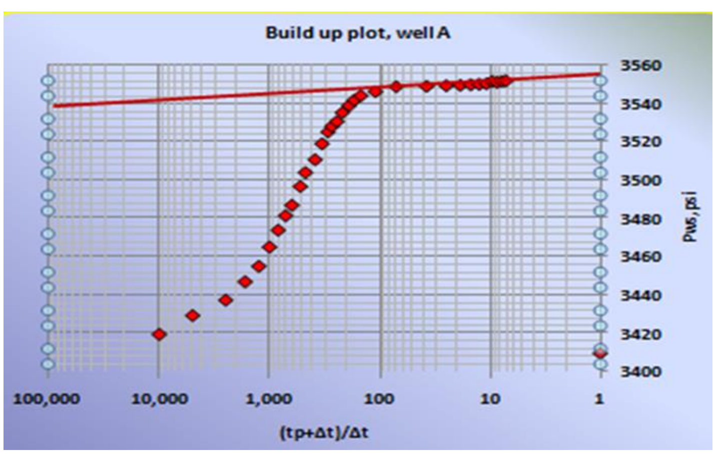

Fig. 1. Graph of Well A test using Horner’s plot

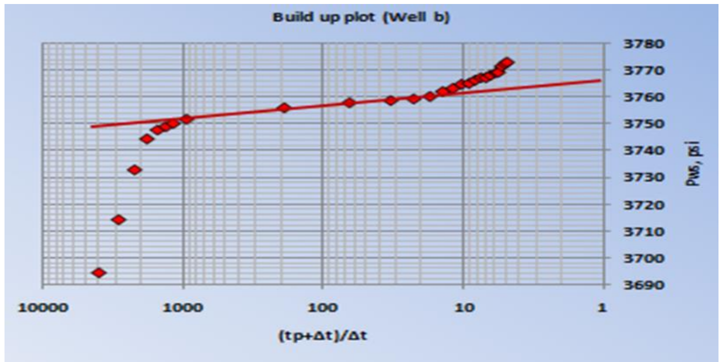

Fig. 2. Graph of Well B test using Horner's plot

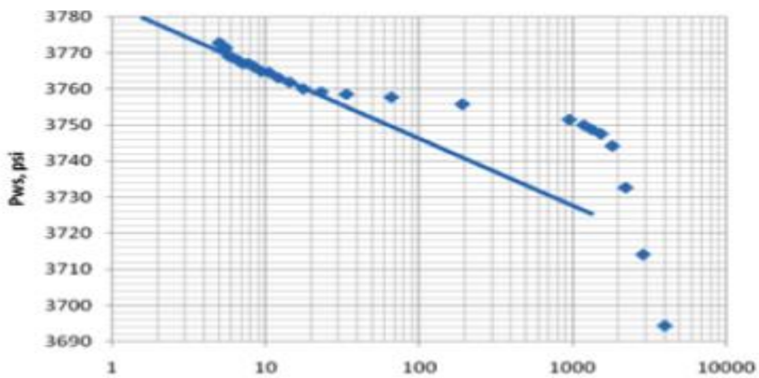

Fig 3. Graph of Well C test using Horner's plot

Tab. 7. Summary result for Well A, B, and C

Parameter	Well A	Well B	Well C
Initial reservoir pressure psi	3 556	3 784	3 784
Transmissibility (mD-ft/cP)	13 839.7	12 106.55	12 106.53
Flow capacity (mD-ft)	41 519.1	64 16.469	64 16.469
Flow efficiency	0.372233	1.217795	1.217795
Pressure drop due to skin Psi	92.04947	-22.8293	-22.8293
Effective permeability (MD)		213.8823	213.8823
Skin factor	10.59257	-1.45949	-1.45949
Damage ratio	2.686489	0.821156	0.821156
Potential production rate without skin (B/D)	-	808.0178	808.0178
Productivity index (B/D/psi)	4.944418	9.387521	9.387521
Radius of investigation ft	900.1313	1 536.943	1 536.943
slope psi/cycle	10	18	18
Effective permeability (m D)	471.8079	-	-
R-Factor	0.627767	0.217795	-0.2000

4.1. Discussion of results

Three wells were analyzed as shows in Figs. 1, 2 and 3. The result from the study shows that the well A has damage having R-factor of 0.62. R-factor of >0.6 means the formation is damage. However, well B and C have R-factor of 0.22 meaning the reservoir is undamaged. The skin factor in well A is 10.6 which is high indicating that the reservoir needs to be stimulated. On the other hand, well B and C have skin of (-1.45) which is a negative skin indicating that the reservoir is not damage. In addition to, damage ratio due to skin is 2.68 in Well A while Well B and Well C is 0.82. Table 7 shows the summary of the different well test analysis carried out in this research work. In conclusion, well A needs to be stimulated. While B and C is enhanced or stimulated.

5. Conclusion

From the well under the study (well A, B, C), the following conclusions can be drawn:

i. The evident from the calculated permeability, skin factor, flow efficiency shows that damage occurred in well A.

ii. Any damage to the near wellbore formation created by drilling & completion can act as a barrier to the movement of fines through the formation.

iii. Mobile fine in producing formation can lead to pore blockage, which will affect the well productivity

5.1. Recommendation

This study recommends that for good profitability in the oil business and minimization of damage from work over fluids, drilling fluids and completion fluids in the Niger Delta wells, the following should be done:

i. Use fluids which are compatible with formation and its content if possible.

ii. Good stimulation jobs should be properly carried out on a well before putting it into production to avoid damage to the well.

iii. Build up test and analysis should be performed on newly completed wells, especially the exploratory wells to determine the onset of formation damage by indicators lie the R-factors, skin factor.

iv. Minimize exposure time of drilling and completion fluids as much as possible.

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To whom correspondence should be addressed: Dr. K. K. Ihekoronye, Petroleum Engineering, Federal University of Technology Owerri, Nigeria