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ABSTRACT: *-Formation damage can**incur**considerable cost for remediation and deferred production. Thorough understanding of the formation damage mechanisms, stringent measures for its control and prevention, and effective and efficient treatments are the keys for optimum production strategies for oil and gas fields. WELL 4X was investigated in this study to properly diagnosed and evaluate productivity in OREDO FIELD and Bottom Hole Pressure survey was used from Bottom Hole Pressure analysis in addition to the information of the well production history and reservoir data available to determine and assess the extent of the formation damage in the well. The WELL 4X was stimulated using Acid Foam Diversion Techniques to enhance reservoir productivity and increase economic operations. The stimulation job done on the well showed a peak increase of production from 850 bbl/day to 3200 b/d before it declined to 2150 bbl/day, and finally maintained an average stabilized rate of 2000 bbl/day. It has to be established that the treatment method on WELL 4X using Acid Foam Diversion Techniques and the Bottom Hole Pressure survey conducted on the WELL 4X in OREDO FIELD is found to be efficient in the determination and evaluation of formation damage.*

KEYWORDS: *- (Bottom Hole Pressure, Formation Damage, Permeability, Stimulation, Well 4X)*

I. INTRODUCTION

Producing formation damage is the impairment to reservoir (reduced productivity) caused by wellbore fluids used during drilling/completion and workover operations. It is a zone of reduced permeability within the vicinity of the wellbore (skin) as a result of alien-fluid invasion into the reservoir **rock**(***Dake, 1978***). This reduced production results in an indeterminate reduction of the efficient exploitation of hydrocarbon reservoirs. The situation is both undesirable economically and operationally, hence, it is considered as a difficult problem to the oil and gas **industry**(***Leontaritis et al., 1994***). As a result conducting an in-depth analysis of the producing formation to customize a fluid specific in **OREDO FIELD** that will help minimize formation damage and thus increase production rate is of paramount interest to the general economics of the field.As expressed by ***Amaefule et al., 1988***, “Formation damage is an expensive headache to the oil and gas industry.” ***Bennion,1999*** described formation damage as, “The impairment of the invisible, by the inevitable and uncontrollable, resulting in an indeterminate reduction of the unquantifiable!” Formation damage assessment, control, and remediation are among the most important issues to be resolved for efficient exploitation of hydrocarbon reservoirs (***Civan, 2005***).Formation damage does not occur naturally.

It is caused by physio-chemical, chemical, biological, hydrodynamic and thermal interactions of porous formation, particles, and fluids and mechanical deformation of formation under stress and fluid shear. Fluids introduced into the formation during various operations carried out to bring a well on stream and also during the life of the well have the potential of reducing the well permeability and impairing productivity. Formation damage can occur due to any one of the following physical or chemical interaction between invading liquid phase and the reservoir rock constituents. This problem leads mainly to potential clay swelling, wettability alteration and potential water blocking.Formation damage indicators include permeability impairment, skin damage, and decrease of well performance. As stated by ***(Civan, 2000)***, “Formation damage is not necessarily reversible” and “What gets into porous media does not necessarily come out.” ***Beadie, 1995*** called this phenomenon “the reverse funnel effect.” Therefore, it is better to avoid formation damage than to try to restore it.

A verified formation damage model and carefully planned laboratory and field tests can provide scientific guidance and help develop strategies to avoid or minimize formation damage. Properly designed experimental and analytical techniques, and the modeling and simulation approaches can help understanding diagnosis, evaluation, prevention remediation, and controlling of formation damage in oil and gas **reservoirs.**The consequences of formation damage are the reduction of the oil and gas productivity of reservoirs and non-economic operation. Therefore, it is essential to develop experimental and analytical methods for understanding and preventing and/or controlling formation damage in oil and gas-bearing formations (***Gary and Rex, 2005).***The laboratory experiments are important steps in reaching an understanding of the physical mechanisms of formation damage phenomena. "From this experimental basis, realistic models which allow extrapolation outside the scale able range may be constructed" (***Civan, 2000).*** These efforts are necessary to develop and verify accurate mathematical models and computer simulators that can be used for predicting and determining strategies to avoid and/or mitigate formation damage in petroleum reservoirs (***Odeh, 1968)***. Invasion of solids fluid and formation that can leads to particle plugging or fine migration is also another serious concern of formation **damage**.The measure of formation damage is called "skin"(***Jones and Watts, 1971).*** The formation damage obviously reduces well deliverability, drainage efficiency and ultimate recovery. These parameters are key factors to determine the reservoir performance and field development, production test, pressure build-up test or drawdown test indicates formation **damage**(***Matthews and Russels, 1967).*** Comparison with offsets well and careful analysis of production history prior to completion, workover and remedial works indicates formation damage. These indicators are useful tools employed in the investigation of the cause, analysis, severity and location of the damage.

[1]. Over the last five decades, a great deal of attention has been paid to formation damage issues for two primary reasons:
[2]. Ability to recover fluids from the reservoir is affected very strongly by the hydrocarbon permeability in the near-wellbore region. Although we do not have the ability to control reservoir rock properties and fluid properties, we have some degree of control over drilling, completion and production operations. Thus, we can make operational changes, minimize the extent of formation damage induced in and around the wellbore and have a substantial impact on hydrocarbon production.
[3]. Being aware of the formation damage implications of various drilling, completion and production operations can help in substantially reducing formation damage and enhancing the ability of the well to produce **fluids**(***Marek, 1979)***.

Aims of the study : The fact that all wells are susceptible to damage is indisputable as such this study goals were to carry out a stimulation program to minimize formation damage and improve well productivity while maintaining the integrity of the formation and to assess and determine the damage level in the formation.

Scope of the study:The study mainly dwells on Bottom Hole Pressure (BHP) Survey, Production history and Well Production Logging Data. Examinations of well performance before and after stimulation job were studied. Adequate analyses on observations from collected field data from **Nigerian Petroleum Development Company(NPDC, 1997) OREDO FIELD** were made.

II. COMMON FORMATION DAMAGE CAUSES, TREATMENTS AND PREVENTION

Barkman and Davidson (2003),Piot and Lietard (2000),Amaefule et al., (1988),Bennion and Thomas, (1991, 1993), and many others have described in detail the various problems encountered in the field, interfering with the oil and gas productivity of the petroleum reservoirs. **Amaefule et al., (1988)** listed the conditions affecting the formation damage in four groups:

-Type, morphology, and location of resident minerals; -In situ and extraneous fluids composition; -In situ temperature and stress conditions and properties of porous formation; and -Well development and reservoir exploitation practices.

Amaefule et al., (1988) classified the various factors affecting formation damage as the following: (1) Invasion of foreign fluids, such as water and chemicals used for improved recovery, drilling mud invasion, and workover fluids; (2) Invasion of foreign particles and mobilization of indigenous particles, such as sand, mud fines, bacteria, and debris; (3) Operation conditions such as well flow rates and wellbore pressures and temperatures; and (4) Properties of the formation fluids and porous matrix. **Table 2.1** by **Hower, (1977)** delineates the common formation damage mechanisms in the order of significance. ***Bishop, (1997)*** summarized the various formation damage mechanisms described by ***Hower, (1977)*** and ***Bennion and Thomas (1993)*** as the following ***(after Bishop, ©1997 SPE; reprinted by permission of the Society of Petroleum Engineers):***

[1]. Fluid–fluid incompatibilities, for example emulsions generated between invading oil-based mud filtrate and formation water.
[2]. Rock–fluid incompatibilities, for example contact of potentially swelling smectite clay or deflocculatabl kaolinite clay by non-equilibrium water-based fluids with the potential to severely reduce near wellbore permeability.
[3]. Solids invasion, for example the invasion of weighting agents or drilled solids.
[4]. Phase trapping/blocking, for example the invasion and entrapment of water-based fluids in the near wellbore region of a gas well.

Table 2.1: Formation Damage Quick Reference Guide (Hower, W. F., 1977)

Damage	Cause	Treatment	Prevention
Mechanize particle plugging	Dirty drilling fluids and invasion	4Cl acid of Hcl/Hf back flowing	Use compatible fluid
Fines migration	Excessive kotinite chlorides or illites	Hcl/Hf acid over flush 5' out	Bring well on slowly with no high PH fluids
HF precipitate	Sodium, Calcium or Potassium in formation for fluids	Insoluble None	NH_4CL over flush, HCl preflush
Iron precipitation	Excessive Iron in formation or fluid	HCl acid	Sequestering agent acetic acid preflush
Fluid loss control residue	Inefficient removal	Gels/$CaCO_2$/Salt HCl and sand. Esters oil soluble resin-xylene	Prepack perforation before placing. Do not use resin in sand control situation
Organic deposition	Asphaltenes and paraffins cool fluid in formation with strong acid	Xylene or Toluene soak	25 GPF Xylene ahead of acid treatment
Scale	Minerals in produced water	Carbonates HCl and hydride or gypsum	Analyse produced fluid may require routing treatment
Mechanism wettability changes	Oil based fluid acid additives	Mutual solvent soak	Xylene in gas well
Emulsions	Incompatible fluids	Lab. Recommendations	Lab. Test before acid. Do not use fluid carbon surfactants in oil or condensate wells.
Water block	Excessive fluid losses, water conning excessive illite clays	HCl + HF + Methanol	Limit fluids in gas well. Include methanol in acid in gas wells.

(a). Drilling Induced Formation Damage

Wells have to be drilled as fast as possible for economic reasons. To increase the penetration rate, it is appealing to reduce the fluid loss or control the drilling fluid. During drilling of 10, 000 ft. well approximately 600 reservoir barrels of fluid may be lost in a typical formation. High value of filtrate invasion may result from deliberate choice of high penetration rates. The liquid phase of a drilling fluid contains many potentially-damaging compounds because filtrate invasion can be very deep **(Table 2.2).** The plugging of the reservoir-rock pore spaces can be caused by the fine solids in the mud filtrate or solids dislodged by the filtrate within the rock matrix. To minimize this form of damage is to minimize the amount of fine solids in the mud system and fluid loss ***Civan, (2000).***

Table 2.2: Depth of Filtrate Invasion

Time (Days)	Oil-Based Drilling Fluid (Inch)	Low-Oil Based Drilling Fluid	Water-Based Drilling Fluid
1	1.2	3.3	7.7
5	4.6	1.1	12
10	7.7	17	18
15	10	21	23
20	12	23	27
25	14	29	31
30	16	32	34

III. RESEARCH METHODOLOGY

(a).History and Status of WELL 4X (OREDO FIELD): The **OREDO FIELD** considered was assigned **WELL 4X** due to the sensitive nature of the data ***(NPDC 1997).*** The well was drilled to a depth of **1147 ft.** and completed as two string dual (TDS) on **A8.2 Sands** in April 1991. The WELL came on stream in February 1992. During a well re-entry in March 1993, both intervals were consolidated to arrest sand production. Interval Gravel Pack (IGP) was installed across both intervals during a re-entry in 1994 to arrest high sand production since **Eposand consolidation** was not effective to arrest the sand production.

A8.2 (9846.28″ - 9856.17″): IGP: When the interval came on stream in February 1992, the production rate was 700 – 800 b/d. sand of about 2ppt and water cut of 22 % was noticed in December 1992. The water cut rose steadily to about 51 % in April 1996 thus necessitating a water exclusion job in May 1996. After the water exclusion job, the water cut subsided to 8.1 %. The well was observed to have experienced a drastic drop in productivity index from 36.4 b/d/psi in March 1992 to 3.48 b/d/psi in February 1996 due to the encroachment of water. This indicated impairment as such the well was re-entered to install IGP across this interval. The BHP survey on **WELL 4X A8.2 Interval Gravel Pack analyses** is shown in **Table 4.1.**

(b). Stimulation Programmeof BHP Data of WELL 4X
The well is stimulated by investigating the following rock and fluid properties

Permeability K

$$K = \frac{162.6 Qo\mu o\beta o}{mh} \quad (1)$$

Total skin

$$S = 1.151\left[\frac{P1hr - Pwf}{m} - log\left[\frac{K}{\emptyset\mu oCt\, rw^2}\right] + 3.23\right] \quad (2)$$

Damage skin due to formation damage

$$S_d = \frac{hp}{ht}[s - sp] \quad (3)$$

$$S = S_d\left[\frac{ht}{hp}\right] + Sp \quad (4)$$

Where $S_d$is the skin due to formation damage

$$Sp = \left[\frac{ht}{hp} - 1\right]\left[ln\left[\frac{ht}{rw}\sqrt{\frac{KH}{KV}}\right]\uparrow^{-2}\right] \text{ Assuming } \frac{KH}{KV} = 1 \quad (5)$$

Where S_p is the skin due to incomplete perforation

Pressure drop due to total skin

$$\Delta Pskin = 0.869ms \quad (6)$$

Pressure drop due to damage skin

$$\Delta Pskin = 0.869ms \times m.\,S_d \quad (7)$$

Pressure drop due to incomplete perforation skin damage

$$\Delta Pskin = 0.869 \times m.S_p \quad (8)$$

Productivity Index (J)

$$J = \frac{QO}{Pr - Pwf} \quad (9)$$

Flow Efficiency

$$F.E = \frac{(P^* - Pwf - \Delta Pskin)}{P^* - Pwf} \times 100 \quad (10)$$

Damage Ratio

$$DR = \frac{1}{F.E} \quad (11)$$

Estimated Damaged Ratio

$$EDR = \frac{(Pmt - Pff)}{m(logtp + 2.65)} \quad (12)$$

R – Factor

$$\frac{\Delta Pskin}{P^* - Pwf} \quad (13)$$

Hence, if r> 0.60, it means the well needs to be stimulated

Radius of Investigation

$$R_1 = \left[\frac{K\Delta t}{948\emptyset\mu Ct}\right]^{0.5} \quad (14)$$

Transmissibility

$$\frac{Kh}{\mu} \quad (15)$$

Treatments of A8.2 Sand of WELL 4X: Subsequent to the configuration of the presence of formation damage, treatment programme recommended was initiated in the well using the following:

Coiled Tubing Stimulation for WELL 4X

Perforation	9846.28″ - 9856.17″
Tubing Size	$2\frac{2''}{3}$

Treatment Programme Requirement using Acid Foam Diversion Techniques: Stimulation of interval to remove any near wellbore damage caused by the migration of formation sand or fines was done using "**Acid Foam Diversion Techniques"** and the following treatment procedure were employed.

[1]. A drift was made to the well nipple to make sure that the tubing was free

[2]. The coiled tubing surface was run to tubing tail while circulating with diesel. The hole was circulated clean.

[3]. Stimulation chemicals were pumped into the perforation as per treatment recipe.

[4]. The well was opened up and produced clean

[5]. The well was produced to potential bean up steps of $\frac{16}{64}''$ to a maximum bean of $\frac{36}{64}''$ while monitoring for sand, GOR and water.

IV. RESULTS AND DISCUSSION

Results

Table 4.1: Reservoir Data for WELL 4X

Description	Unit	Value
h	Ft.	37.784
r_w	Ft.	0.362
K	Md	1698
Ø	%	18.7
P_d	Psia	3587
Sand/reservoir name		A8.2
T	^oF	185
J	bbl/d/psi	0.854
GLR	scf/bbl	139.2
C_f	Psi^{-1}	8.91×10^{-5}
S_g		0.705
μ_O	Cp	0.238
S_{gw}		1.100
Water salinity	ppm	94712
A	Acre-ft.	2010.4
P_r	Psig	4377
B_o	bbl/stb	1.805

Table 4.2: Completion Data for WELL 4X

Description	Unit	Value
Productivity casing size	Inches	9 5/8
Casing weight	lbs./ft.	58
Casing grade	Types	N-80
Casing depth	Ft.	11347
Tubing size	Inches	3 ½
Tubing weight	lbs./ft.	9 1/2
Performance diameter	Inches	1.12
Top packer size/type	Inches	9 5/8 A5D Packer
Top packer depth	Ft.	9588.40
Sand exclusion	Types	IGP
Flow at surface	Types	Tubular
Performance shot density	SPF	12
Gravel pack length	Ft.	30

Table 4.3: Production Report Data for WELL 4X before Stimulation

Date	Size (Inch)	THP (Psig)	Gross Production (B/D)	BS & W (%)	GOR (scf/bbl)	Sand (ppt)
02/92	20	460	780	1	200	2
02/93	22	460	950	1	200	2
12/93	24	500	1300	2	250	4
03/94	36	360	2500	9	150	7
08/94	40	310	3200	16	150	9
02/95	44	280	3170	18	150	9
11/95	42	280	3080	22	180	8
04/96	42	290	3000	52	200	7
12/96	24	250	1750	23	300	4
05/97	36	150	850	10	175	2

Table 4.4: Production Data for WELL 4X after Stimulation

Date	Bean Size (/64 Inch)	THP (Psig)	Gross Production Rate	BS & W (%)	Sand (ppt)
10/97	36	150	2150	0	10

02/98	40	180	2050	1	14
09/98	16	310	1900	2	12
02/99	20	280	1000	0	8
11/99	22	250	1000	1	10
04/00	28	200	920	0	16
12/00	32	200	900	0	12
04/01	36	190	800	0	10
11/01	36	160	700	2	14
03/20	36	170	600	1	18
11/02	36	150	550	1	22

Table 4.5: Production performance of offset wells completed on the same sand/formation

Wells	**Size (/64)**	**THP (Psig)**	**Gross production rate**	**BS & W**	**GOR (scf/stb)**	**Sand (ppt)**
9X	40	500	980	20	105	12
7X	22	100	1800	2	170	0
2X	48	200	3420	5	300	6
4X	36	180	650	5	280	4

Table 4.6: Pressure versus Time Readings for WELL 4X

Δt (hrs.)	**Pws (Psia)**	**(tp + Δt)/Δt**
0	2685	0
1	2763	721
2	2805	361
4	2819	181
5	2825	145
7	2828	104
9	2830	81
12	2831	61
20	2831	37
60	2837	13
120	2840	7
300	2842	3.4
420	2842	2.7
550	2842	2.3
620	2843	2.2
720	2843	2.0

Table 4.7: Stimulated BHP Data for WELL 4X

Data	**Unit**	**Value**
K	Md	774
S		14.65
Sd		3.36
ΔPskin	Psi	101.8
ΔPskin damage	Psi	23.4
J	Stb/d/psi	6.203
F.E	%	37.2
DR		3
EDR		3.6
Transmissibility	Md ft./cp	26093.2
ΔPskin perforation	Psi	35.58
R – Factor		0.628

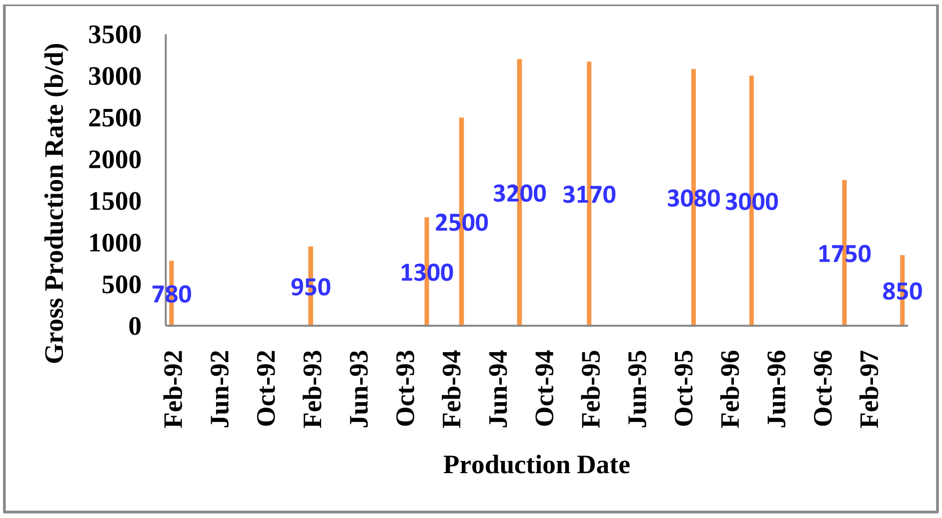

Figure 4.1: Production Rate of WELL 4X before Stimulation

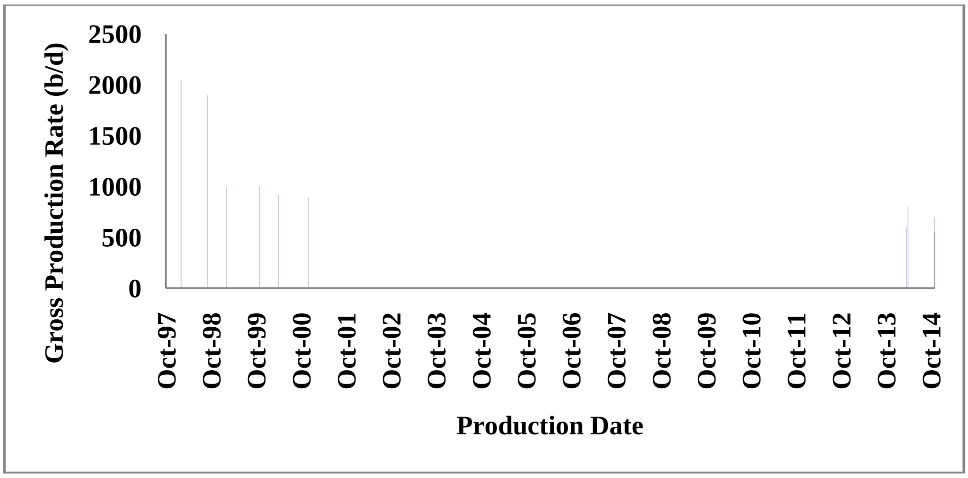

Figure 4.2: Production Rate of WELL 4X after Stimulation

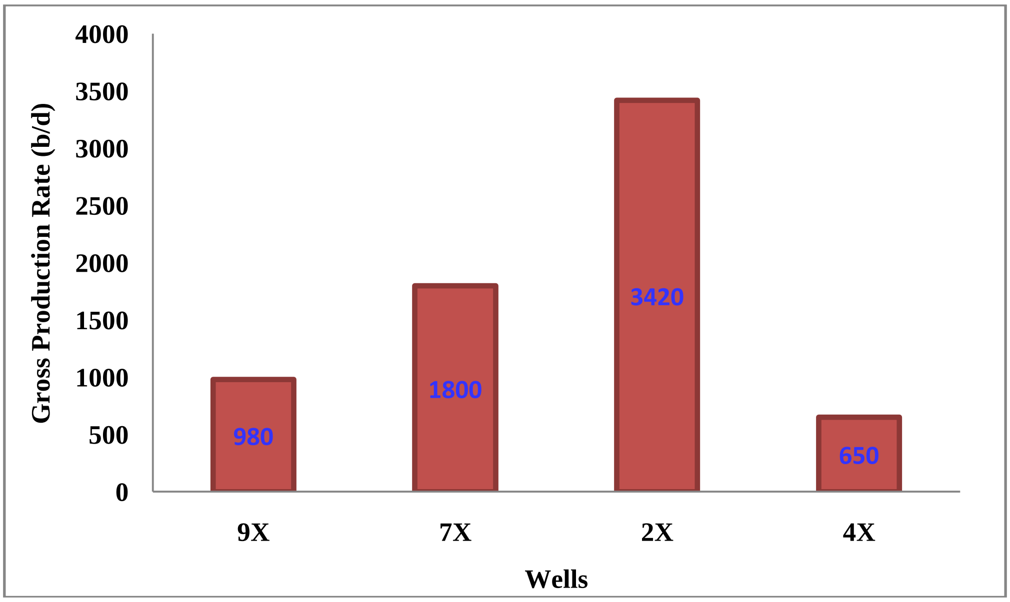

Figure 4.3: Comparison of WELL 4X with Offset Wells

III. DISCUSSION OF RESULTS

Analyses of Production Data of WELL 4X: Before stimulation **(Table 4.3),** the production rate was lower to the production rate obtained after stimulation **(Table 4.4)** as were shown in **Figures 3.1** and **3.2** respectively. The appreciable increase in the production after the well has been treated shows that the treatment techniques were very effective and efficient. The decline in production rate observed in the well was due to the increase in water encroachment into the well and the reduction of tubing head pressure over the period.

Analyses based on comparison with offsets wells completed on the same sand/formation: Table 4.5 and **Figure 3.3** shows the recent production tests conducted on wells of the same block. It is observed that all the wells are producing reasonably except **WELL9X** that seems to be declining. This does not in any way suggest impairment as such decline may be as a result of reservoir sand permeability, completion configuration, reservoir pressure or position of the well in the reservoir.

Pressures versus Time Evaluations of WELL 4X: The available data **(Table 4.6)** of the well BHP survey taken in **1997** as presented in the well history and corresponding drop in pressure rates suggest that the well interval is significantly impaired. The stimulation job in **1997** has little significance on the production rate.

Analyses of the BHP Data of WELL 4X: From **Table 4.7**, the high permeability shows the measure with which the fluid can flow through the formation except that the interval around the wellbore has been significantly damaged. The total skin of 14.65 indicates flow restriction, hence the presence of damage and reason for stimulation programme to be initiated. The flow efficiency of about 40% indicates the flow capacity of the well. The low rate of flow capacity shows that the well is producing far below its potential and the need for efficient stimulation to be introduced. The damaged and estimated damaged ratio of average 3 shows that the well deliverability should have been thrice its present production rate. The radius of investigation of 2441 ft. show the radial distance from the well where the pressures have been significantly affected by the active well. The high well transmissibility shows the well potentials and the measure of the reservoir rock to produce fluid.

Analyses of the Well Performance after Survey : The total skin value of **14.65** estimated from the BHP survey show that the well is damaged with considerable percentage of pressure drop due to total skin of about 102 Psi **(Table 4.7).** After the stimulation job done by **"Acid Foam Diversion Techniques"**, the well produces reasonably from **650 b/d** with a choke performance of ″42/64″ and skin due to damage of 3.27 to **2150 b/d** with a bean size of ″42/64″ at a significant amount of THP and BS & W. The sudden and gradual decline of the production rate in December 2002 to about 550 b/d was due to mechanical action on the well like production logging tools and sand injection which causes formation damage. However, it is concluded that the treatment method introduced in the well was very active and efficient.

IV. CONCLUSION AND RECOMMENDATIONS

Conclusion : To make decision on the presence and/or degree of permeability alteration of a well, formation damage valuation on wells are required to generate the necessary sets of information. Based on the analyses of data conducted on **WELL 4X**, the following conclusion could be made:

(1). The improvement in the production rate suggests that the stimulation job initiated in the well was effective and successful.
(2). The sharp decline of the production rate suggests mechanical action in the well which may be from production logging tools.
(3). The gradual decline of the amount of production in the well suggests the need to carry out sand control programme.

Recommendations : The following recommendations become vital based on the conclusion deduced from **WELL 4X.**

(1). Investigation on the sharp decline in production rate as a result of mechanical problem should be further carried out to ascertain the cause and also to checkmate it.
(2). Reservoir conditions are prone to alterations and as such continuous production data update before carrying out any treatment job should be done to avoid any likely failure.
(3). Intensive efforts should be consciously directed to formation damage preventive measures from drilling to production, well completion to workover activities. It is important that mandatory tests be run with all the chemicals and mixtures that are to be used on the job and the **WELL 4X** sand should be reconsolidated.

NOMENCLATURE

Ø	Porosity
A	Cross sectional area
BHP	Bottom Hole Pressure
Bo	Oil formation volume factor
BOPD	Barrel Oil per day
BS & W	Base Sediment and Water
Ct	Total compressibility factor
DR	Damage ratio
F.E	Flow efficiency
GOR	Gas-Oil Ratio
γ_w	Wellbore radius
h	total reservoir thickness
h_p	height of perforation
h_t	Height of interval
IGP	Internal Gravel Packing
J	Productivity index
K	Permeability
K_a	Average permeability
K_h	Horizontal permeability
K_v	Vertical permeability
m	Horner's plot slope
P^*	Reservoir pressure
P1hr	Extrapolated pressure
ppt	Part per thousand
Pwf	Flowing well pressure
Pws	Static well pressure
Qo	Oil production rate
r_a	Effective wellbore radius
r_e	damage radius
S	Skin factor
S_d	Skin due to formation damage
S_g	Gas saturation
S_o	Oil saturation
S_p	Skin due to incomplete perforation
S_w	Water saturation
t_p	Flow period before BHP Tests
ΔP	Pressure change
ΔPskin damage	Pressure drop due to damage skin
ΔPskin	Pressure drop due to skin
Δt	Change in tine
μo	Oil viscosity
EDR	Estimated damage ratio
R – Factor	Radius of investigation
ΔPskin perforation	Pressure drop due to incomplete perforation skin damage
NPDC	Nigerian Petroleum Development Company

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