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Stimulating High Water Cut Wells in Some Selected Niger Delta Reservoir

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ABSTRACT
This paper describes a successful approach for stimulating high water cut wells to improve their productivity without significantly increasing water production. Results obtained from ten wells treated over the past couple of years have shown it proved performance with little or into increase in water cut. This has helped to change the age long negative mindset on stimulating high water cut wells based on failures of previous techniques. This successful technique demonstrates the possibility of reducing water cut via drawdown reduction and near well bore wettability alteration through the use of an effective two way diversion (i.e. foam and high rate diversion. From the results, there is significant increase in scope for candidates' selection for acid stimulation. The results also show that there is scope for reducing the cost of stimulation wells, due to reduced pumping time and equipment usage. The job designs, execution and post-job evaluation of some candidate's wells are discussed. Post job performance data of trial candidates show over 95% technical and economic success of the jobs. Furthermore, the candidates have also shown significant production improvement over prediction. These performances indicate the possibility of reducing water production through wettability alteration and drawdown reduction. Comparison between treatment results from the new technique and the previously applied methods (using Skin factors, Unit Technical Cost, Productivity Index and Payback Time) have proven the success and superiority of this new approach.
Keywords: Stimulation, water cut, reservoir, productivity, drawdown, wellbore and wettability

INTRODUCTION
Improving the productivity of a high water cut well in heterogeneous sandstone environment using acid systems has -been a great challenge. This stems from the fact that there is high chance of either increasing the water cut or decreasing the productivity further. Common near-well-bore impairment problems include scaling, fines migration, emulsions and water block. Matrix acid-stimulation techniques have been used as the preferred method of removing such well impairments in oil & gas wells in the- Niger Delta Basin.

Most of the time, conventional Mud Acid (HCL:FIF acid mixtures) or any of the other retarded HF acid systems (like Fluoboric acid or in-situ generated HF) are pumped via Coil Tubing with or with Out foam or other diversion system. However little consideration has been given to designing the treatment fluids to accommodate problems associated with high water cut wells' stimulation. Hence, previous treatment attempts have been with mixed results.

The average success rate experienced with the common approaches could be attributed to one or -more of the following reasons: poor candidate selection, poor diversion, fluid designs and wrong placement method.
The rapid spending of Mud Acid with clays and possible matrix de-consolidation in the near well-bore area with subsequent precipitation of various acid reaction by- products make the conventional HF acid systems inappropriate for high water cut well stimulation.
Consequently, a new approach that handles these problems as well as removes the damage without increasing water cut of the interval was developed. This approach has been tested on wells with water cuts ranging from 20% to 60%. It combines the scale-inhibiting, clay-coating, formation-wettability power of the Phosphoric Acid complex (Named "HV-" acid) with effective fluid design, foam diversion and high rate pumping to deliver better treatment.

Case for Action

Wells originally drilled to produce oil and/or gas may eventually produce high water along with the hydrocarbons either due to natural water encroachment, high permeability fingering or poor cement bond. Producers are burdened with problems associated with water production not only because of increasing cost of handling but for other problems associated with high water cut wells, as detailed below:
Such wells suffer early production decline and formation damage. The damage arises from mobile water dissolving natural 'cementing' materials from the matrix and consequently, fines are set loose within the formation matrix. These fine particles clog the reservoir pore spaces, plugging the hydrocarbon flow path. Dissolved scale ions also crystallize from formation water and are precipitated into connected reservoir pore spaces, fractures and near-well-bore area of the perforations. These problems are enhanced by temperature change due to water ingress, pressure drop, fluid incompatibility and super-saturation[2].
Secondly, high water-cut wells are prone to the formation of stable emulsion around the wellbore[2]. An oil field emulsion is that due to water droplet dispersed in oil or oil droplet dispersed in water or complex mixture of oil and water droplets. The stability of emulsions down-hole is greatly enhanced by third party component such as fines, crystallized scales, iron particles from rusted completion tubular and incompatible acid blend or surfactants. Emulsion when formed down-hole will restrict hydrocarbon production by blocking the pore spaces and increasing fluid drag force via increased fluid viscosity.
Thirdly, high water-cut wells are prone to water-block problems. Water-block is caused by change in formation wettability from original water-wet state to oil-wet state, especially during emulsion problem or when wells with high water cut are closed in. Water-block reduces the mobility of oil and increases the mobility of water with consequent reduction in oil production. When formation becomes water-blocked (or simply oil-wet), oil or gas is preferentially attracted to the surface of the reservoir rock. This often leads to more immobile oil films with increasing thickness across the formation surface and a consequential reduction in fluid flow path.
Fourthly, there is usually a reduction in tubing-head pressure, with a resultant decline in total fluid production due to increased hydrostatic head as water-cut increases,
Lastly, as the damage increases around the critical well- bore, there is the continuously increasing draw-down. Reducing this draw-down associated with removable damages should therefore prevent early loss of well and improve total oil production and reservoir recovery efficiency.
In view of all the problems enumerated above which are associated with high water cut wells, there is need to improve the wells' productivity without increasing water cut.

Old and New Approach Compared

In the past, majority of high water cut wells in Niger Delta were stimulated with Mud Acid systems, retarded HF system like flouboric acid or in-situ release HF system. Some of the treatment incorporates diversion pads ahead, while many were carried out relying on high rate pumping approach. Many of the pre-treatment infectivity tests were done with organic solution like diesel or diesel-xylene mixtures. While laboratory testing included emulsion-tendency testing, fluids compatibility tests, acid solubility tests and wettability test, many of the usual techniques are with shortcomings, which results in failures. The shortcomings of these old techniques have

Choice of fluid for injectivity test

It is necessary to confirm the feasibility of pumping fluid into the formation before mixing the treatment recipe.

Conventionally in most low pressure or sub-hydrostatic wells, Diesel oil or Diesel/Xylene mixture is often used for pre-stimulation injectivity test. Such organic fluid systems would pose little or no problem in dry oil reservoirs. However, the oil phase fluid is often the source of problem when the near well-bore water saturation is high (as in high water cut wells). The oil- phase fluid will. not only further oil-wet the formation but will also occupy the pores in the water-producing zones.

This has the effect of reducing oil mobility, increasing water mobility and dc-stabilizing the foam pad primarily placed to divert acid fluids system from the water zone or high permeable zones. This new approach however, utilizes instead a water-wetting Ammonium Chloride salt solution (3% NH4CL solution) for the injectivity test.

About 10 to 2Obbls in excess of Coil Tubing or Tubing content of NH4CL solution is used for the injectivity. This water wetting fluid acts as a whole conditioning fluid prior to foam pad placement. NH_4CI is compatible with most formation, acid and foam systems. Where the injectivity is low and below expectation, acid is spotted with coiled tubing and injectivity repeated.

Fluid Designs

Fluid design (or acid recipe) is dependent on the damage mechanism. The notable source of production impairment in the treated reservoir sands are due to tines migration, and to a lesser extent clay dispersion and swelling[1]. An associated damage mechanism is also suspected to be scale deposition caused by filtrate invasion with occasional problems of paraffin, asphaltene and emulsion formation[2]. Principal problems associated with Sandstone Matrix acidising in the Niger Delta emanate from rapid Mud Acid reaction leading to dc-consolidation of the near welibore matrix and poor acid penetration'. To a lesser extent, job failures could be attributed to fluids incompatibility and precipitation of reaction by-products.

With reference to **Table 1**, conventional acid recipe in section A is designed with solvent spearhead for reservoirs with heavy oil or case history of organic deposits (Wax Asphaltene, Paraffin etc.). Acidizing is either with or without foam pad and spacer for high water cut wells. From the outlined pumping sequence [Spearhead (an Oil phase) - Foam -Foam Pad - Acid], it is obvious, for the same reason enumerated above, that the foam will be destabilized by the spearhead (figure 2).

Inclusion of Spearheads solvent after foam pad therefore not only allows foam stability but also prevents wastage of spearhead into unwanted zones (figure 3). The modified sequence (Foam - Foam pad - Solvent (an Oil phase) - Acid) minimizes possible foam contamination by the organic solvent (Spearhead).

Placement and Diversions

Successful stimulation requires effective fluid placement into the Zone of interest. Several diversion techniques have been developed to improved treatment fluids placement to zone of interest. Mechanical diversion techniques include Straddle Packers, Wash Cup and Ball Sealers, while chemical techniques use viscous fluids, foam solutions and oil soluble resin: Since any fluid pumped will always take the path of least resistance as illustrated in figure 1, it is vital to carefully select the placement method and diversion techniques during stimulation of high water cut wells, Most of the candidates presented in this paper are high permeable and heterogeneous reservoirs with gravel pack installed across the intervals that ranges from 10 to 50ft long. Acid placement in a few of the wells was carried out using Coil Tubing while most were executed by bullhead of treatment fluid into the formation. Foam diversion was used in the selective stimulation of oil zone preferentially to water zone and to aid in the effective distribution of treatment fluids in zone with more than l5ft of perforation (figure 3).

Identification of water source or point or inflow into the immediate well-bore is essential in the design of roam pad for acid diversion from water zone. Since fluid pressure takes the path of least resistance, matrix stimulation of intervals having water influx from high permeable zones in a heterogeneous reservoir will benefit more from foam pad diversion. Treatment in a reservoir where water influx is from low permeable zone (water encroachment or mature coning effect) or zones in a homogenous permeability could also be achieve with increasing foam pad. In this case, the foam is expected to degrade faster in the oil phase. Volume of foam required is estimated as 25 to 30 percent of HV-HF treatment volume. A foam quality of 65-70 percent was used.

Maximum Safe Injection Rate and Pressure

The decision to place treatment fluids via Coiled Tubing or through the completion tubing is a function of the completion tubing size and type, maximum injection rate possible and length of interval to be treated. The formation fracture pressure (or maximum surface pumping pressure) is also considered in the decision. Coil tubing is the preferred choice when long intervals (greater than 200ft) having permeability contrast greater 300md (according to Paccaloni and Tambini, 1990, Ref. 3).

Preference is also given to the use of CT For horizontal wells with zones greater than 400ft. The paper also recommend that bull heading at maximum safe pressure is a suitable approach to short string interval stimulation (figure 5) where the Coil Tubing (CT) has no access to the well-bore. The rate you get by using the CT can also be limited. Furthermore, coiled tubing usage in some high producing interval with high water cut have been found to be inappropriate due to this rate limitation (max of 1.5bpm and 2.5bpm in 1.25 and 1.5 inches respectively, even with friction reducers). Most fluid (even foam pad) pumped ahead using coiled tubing degrade before the acid injection due to long pumping time at the low rates, leading to stimulation of water zone and reduction in acid penetration depth. A successful treatment was therefore achieved via the combination of high rate pumping (bull - heading) of diversion fluid with foam diversion (otherwise called two-way diversion).

The maximum injection rate and surface pumping pressure are calculated using equations 1 and 2. The skin factor in equation I is obtained from Nodal Analysis or from Bottom Hole Pressure survey data analysis.

During high rate and foam diversion operations, production tubing is pickled with 10% HCL. The pickling fluid is usually nitrified and lifted out of the tubing (with plug set in the deepest Nipple profile) to prevent ferrous scales/rust from either contaminating the stimulation recipe or getting to the formation. Foam pad is first displaced into the formation at low rate of 0.2bpm. This would assist the than stability in the water zone and its dc-stabilization in the oil zone. The Pre-flush, main-flush and over-flush are then displaced at maximum allowable pressure. This will ensure that rates are increased for the acid to impact the formation. Where injectivity is low (below expectation) before the acid job, acid is spotted with Coil tubing and injectivity repeated. For very tight formation (injectivity less than 0.7bpm) coil tubing with foam solution is preferred in high water cut wells stimulation because the benefit of the high rate diversion has been limited by the low injectivity after acid spot. The use of coil tubing in acid placement is not being discouraged, but rather emphasis should be placed on careful consideration during high water cut well stimulation.

Hydrogen Fluoride Acid System

Before the introduction of the HF-HV acid system, HF mud acid was the preferred option for high water cut well stimulation. However, the performance of mud acid has been average and inconsistent. This was attributed to the rapid spending of the acid on clays and silicates, and shallow penetration of the acid accompanied by unconsolidation in the near welibore area. Precipitation of various reaction by products of Mud Acid has also been experienced5. Attempts to mitigate these problems by using retarded and in-situ generated HF formulations have given inconsistent results, and have often been prohibitive in their cost'‘‘

"H"V acid is a phosphonic complex with five active hydrogen ions used in the surface and in-situ generation of Hydrogen-Fluoride from Ammonium-Fluoride or biFluoride.

The HV improves the dissolving power of HF on quartz.

The strong anionic charge of HV improves adsorption capacity of HF on positively charged sand grains and holds more silica salt in solution with its chelation ability.
Among the performance features of HV-HF acid is the scale inhibiting property of the HV and the complex solution of Ammonium Phosphonate salt formed during generation of HF. The acid system dissolves scales within the welibore or tubular and inhibits further precipitation of scale compounds. It is believed that these features have contributed significantly to the long-term sustenance of the productivity of treated high water cut wells. Furthermore, the acid system has an extended dissolving capacity which after removing the fines from the critical near weilbore area still continues to dissolve the suspended tines with time, hence significantly retarding subsequent fines re-deposition in this vital area.

Candidate Selection

The process of candidate selection for the treated wells involves a thorough analysis of the production performance history. A full systems analysis is carried out to establish the extent and severity of the damage. In addition, the GOR trend, type of (removable) skin damage and present reservoir pressure are considered in the analyses to adequately assess the feasibility of stimulation. Most of the wells treated fall within a screening envelope for matrix stimulation. This includes economical remaining reserves, P1 (Productivity Index) <10 (obtained from BHP survey), a Flow efficiency (Actual Productivity Index over Ideal Productivity Index) < 0.5 and P1 decline >30%. Good knowledge of water source is important in high water well stimulation. A full systems analysis including cement bond and porosity logs, production and permeability profiles are carried out to establish the source of water and severity of the damage. Intervals mineralogy, reservoir/damage permeability, frequency and history of previous acid stimulation are also considered in the screening. Only candidates with matrix water production and damage skin were considered for acid stimulation while candidates with water leaks from other zones were recommended for alternative remedial actions.

Success Definition

Matrix acidising success is defined in terms of production and injectivity increase, damage skin reduction, pay back time, job cost reduction and unit technical cost. The only reliable ways of measuring the effectiveness of a matrix acidising stimulation method is to prove that the technical and the economical aims are accomplished,
The technical unit cost is defined as the ratio of cost of job over the expected annual production. The cost of the job mentioned above is defined as the total cost involved with the complete job implementation and any additional costs associated with deferred production or injection'. For the cases under review, an acid job is defined as economically successful if the well 'as able to pay for the treatment with a unit technical cost less than 2.7$/bbl. The economic success criteria and results are listed in Table 5, 6.
The technical criteria for the success of a job are given by the effective removal of damage skin, reduced and improved Productivity Index (P1)- Table-2

Analysis

Ten intervals are analyzed in this paper. Eight of these have water cuts ranging between 20% and 60% Table 1-
3. Five of these stimulation candidates had earlier been treated with both Mud Acid and the New HF Acid System within the last two years (Table-5 and -7). The importance of selection of placement methods, injection fluid types and recipes designs also form part of this analysis Table-2, -3 and .4, Figure 1-2.

Technical (Comparison) Analysis

Table-2 shows that all the high water cut wells treated using this new approach demonstrated significant increase in Productivity Index with significant reduction in the proportion of produced water after the treatment. Damage Skin was removed in most cases while true stimulation (with negative skin) were recorded in cases 1 and 10. The negative mindset on risk of stimulating the water zone and converting an oil well to water well is being restructured by this successful approach. However, marginal increases in water cuts were recorded in cases 6 and 9. The partial success experienced in cases 6 and 9 could be attributed to degrading of foam pad by injected oil phase (during injectivity test) and low acid displacement rates used in both cases. Preferential stimulation of some part of the water zone is possible in the absence of diversion fluids or degrading of diversion fluids and low displacement rates. Reduction in water-cut and sustained production seen in majority of these wells are believed to be due to the effectiveness of foam and high water diversion, along with high water-wetting, scale- inhibition and deep-penetrating characteristic of the "HV" system.

Economic (Comparison) Analysis

The wells treated with this technique have shown considerable production increment compared to marginal gains from previous techniques used on the same wells (Figure-4). The analysis in Figure-4 further indicates that the wells treated using the new approach (with New HF Acid System) paid back faster (within 67days) than

previous Mud acid treatments (within 110days) (Figure- 4). All the wells treated with this approach have considerably low unit technical cost with the exception of case 9 with unit cost of 2.74$/bbl (Tablc-5, 6). The higher unit technical cost in Case-9 could be attributed to production loss due to poor placement method used.

Case History 1 (Well-O2SLND) — Fig-3

This interval produces from the D9.OA Reservoir, with perforated at 8,066 — 8,O78ftah. The interval is gravel packed. This well produced at 1,056 BOPD (dry) on bean 40/64" and suddenly declined to an average rate of 235 BOPD on bean 44/64" by 1991. Mud Acid stimulation and Xylene solvent soak of June 1991 increased the production from 235 BOPD on bean 44/64" to 626 RON) on a higher bean of 72/64". The interval was put on gas drawdown, lift in 1991, to sustain the 400 BOPD stimulation gains.

This interval was subsequently stimulated with New HF Acid System via Coil Tubing in June, 1998. A gain of 3,618 BOPD was achieved from the HF-HV Acid System treatment. The BS&W dropped from 4% to 0%. This flat decline was maintained when the well was beaned down for surface facility safety. Treatment payback was just one and a half days. Even after four years (June 1998 toJune 2002), the interval is still maintaining low skin and high oil rate of - I and 3,95OBOPD respectively.

Case History 2 (Well-22SN1J)— Fig. 3

This interval produces from the E2.OE Reservoir, with perforated interval of 24ft from 8,970 — 8,994ftah. The Candidate Selection interval is gravel packed. This well produced to a peak production rate of 2,100 BOPD, BSW 12% on bean 21/64" in 1992, but by 1998 it quit production on choke 60/64, at 1,200 BOPD and I3SW 26%. The well was swabbed, but refused to flow, giving an indication of impairment. The intervals water source was suspected to be due to conning (a result of high draw-down), The draw-down could however not be quantified as recent BHP data was not available, This interval was stimulated with the improved high water cut well stimulation method using foam pad, two- way diversion and the HV-HF acid system in November 1999. After the stimulation, the interval came back to life at initial rate of 2,300 BOPD at zero water cut (i.e. BS&W dropped from initial 26% to 0% on same bean 60/64). For about two years now, this well has maintained a consistently high production rate. This well benefited from the water wetting properties of the HV

system.

Case History 3 (Well-24LNIJ) — Fig. 3

This interval produces from the E2.OX Reservoir sand and perforated interval 9,030—9,080 ftah, IGP. It came on stream at 700 BOPD (dry) on bean 16/64" in April 1979 and produced satisfactorily until the interval was closed in 1984 due to high GOR (4000 scf/stb). The interval remained closed-in until late 1998 when it was opened up again and it produced at about 500 BOPD. The interval was gradually beaned up to average rate of 2000 BOPD and GOR of ca, 1,000scfistb on bean 24/64". This average rate was maintained until late 1996 when water production commenced. The net oil rate then dropped to 1,100 BOPD at BSW of 50% and average GOR of 2,500 sct7stb on bean 52/64". The interval quit incessantly in 1998 and was swabbed in a couple of times.

It came in 1999 after swabbing operation at net oil rate of 1,200 BOPD, BSW of 53% and GOR of 3,000scf/stb on bean 48/64. The interval quit production by November 2000 despite the apparently high GOR.

This interval was however stimulated with the improved high water Cut well stimulation method using, foam pad, high rate diversion and the HV-HF Acid System in November 2001. It then came back on stream and tested at 700 BOPD. The water cut dropped from 53% to 45%, although on a lower choke 24/64". The interval was diagnosed to be producing water from water cone situation. Water production from this interval is sensitive to choke sizes and the estimated present oil water contact is about l0ft from the bottom perforation. For over six months now, this well has since treatment, maintained a consistent production rate with relatively constant water cut (Ca 45%)

Case History 4 (Well-13SNIJ)— Fig 3

The treated interval is from the D5.OX Reservoir with Internal Gravel Pack (IGP) from 7,876 — 7,886ftah (loft). It produced dry to a peak production rate of 2,830 BOPD on bean 40/64" in 1984. The rate gradually declined to an average of 536 BOPD with gradual increase in BSW from 1% in 1984 to a peak value of about 47% on bean 48/64" or 55% on bean 52/64" in 2001. RST data before the stimulation indicated that the Present Oil Water Contact (POWC) at 7825ftss was 8ft to the bottom perforation. The high water cut was suspected to be from conning as result of high draw down (l089psi in 1996). After stimulation with improved high water cut well stimulation method in November 2001, a gain of 900 BOPD was realized with water cut dropping from initial 55% to 48% on same bean 52/64". This well has since treatment, maintain a consistent production rate. Cost of treatment was paid back in just six days. In addition, well is presently generating an additional annual revenue equivalent to 7Million Dollar or 900 BOPD. Case History 5 (WelI-15SNIJ) — Fig 3 The interval produces from the D5.OX Reservoir, having l4ft perforated interval (from 7870 — 7884ftah). It is Internally Gravel Packed (IGP). This well produced dry to a peak rate of 2,547 BOPD on bean 36/64" in 1977. This rate gradually declined to an average of 380 BOPD with gradual increase in BS&W from 25% in 1986, to a peak value of about 50% on bean 52/64" by 2001. RST data before the stimulation indicated that the Present Oil Water Contact (POWC) at 7825ftss was l0ft to the bottom of perforations. The P1 declined from 26.lb/d/psi in 1990 to 8.4 b/d/psi in 1993. The interval was producing at a high drawdown (estimated at 472 psi in 1996 BF1P). This interval was stimulated with the improved high water cut well stimulation method using foam pad, high rate diversion and the HV-1-IF Acid System in Oct. 2001.

A gain of 1500 BOPD was realized with water cut dropping from initial 50% to 41% on same bean 52/64". For more than seven months after treatment, this well has maintained a consistent production rate. Treatment cost payback was just four days and the well is presently generating an additional annual revenue equivalent to about $12.OMillion or 1,500 BOPD.

Case History 6 (WeIl-53SN1J) -Fig 3

The well is completed with an IGP on D6.OJ Reservoir, with perforated interval at 8810— 884Oftah. This interval came on stream in 1991 with an initial dry rate of 225 BOPD, GOR of 1902 scf/stb and THP 84Opsi on bean 16/64. It attained a peak production rate of 2,236 BOPD, BSW of 0%, GOR of 366 scf/stb, and THP of 93Opsi on bean 32/64" in July 1992. This average rate was maintained until October 1993 when a gradual decline started. By November 2001 the well produced at 1,580 BOPD, 30% BSW, GOR 800 scf/stb, THP 645 psi on bean 44/64".

After stimulation in December 2001 with improved high water cut well stimulation method, the interval came in at about I200BOPD on bean 28/64" with water cut of 28% and Tubing Head Pressure (TFIP) of 75Opsi. Well is yet to produce at the pre-treatment bean size but there is scope for bean up, without significantly increasing the water- cut. However, possible increase in water cut above the pre-treatment rate is envisaged due to wettability alteration by diesel used during injectivity testing (recipe A) or de-stabilization of foam pad by the initial solvent used during injection test. Case History

(WeII-45SLND) -Fig 3

This well is completed with IGP on G8.OX Reservoir sand at 10,320 — 10,326. The interval produced at 520 BOPD (GOR = 1,800 scflbbl, BSW =IQ% , THP = 600 psi) on bean 20/64" in December, 1997. Mud Acid stimulation was carried out on the interval in March 1999. The result of this treatment increased production to 300 BOPD, BSW 25% at THP of 800 psi, on bean 20/64". Treatment using the new approach with the new HF-HV acid system was performed on this interval in June 2001. Post treatment result shows a gain of 650 BOPD with a reduction in water cut from 25% to 10%. The bottom of perforations in this well is about 50ft from the water leg. Further analysis indicated that water production was due to high permeability streak and production at high drawdown.

Case History 8 (Well-O7SSTF)— Fig 3

This well is completed with sand consolidation on E6.208 Reservoir with perforated interval at 8,723 — 8,729ftah. The interval was produced at 750 BOPD, BSW of 0% on bean 20/64” in March 1995. A BHP survey carried out in April 1996 indicated a drawdown of 284psi.

A gain of about 24obopd was achieved with mud acid treatment carried out in March 2001. Production also declined drastically from 994bopd to 774bopd, within one month after treatment with mud acid system. Before the New I-IF Acid System with foam pad treatment in March 2001, the interval was producing at 774 BOPD, 20% BSW, and GOR of 954 scf/sth on bean 32/64”.

The interval was treated by the new approach (i.e. two- way diversion with foam pad and HV-HF acid system), but with Coiled Tubing. Well productivity improved from 774 BOPD to 1,IOOBOPD while water cut slightly increased from 20% to 22% on bean 32/64”. Production has since been consistent at average of lO5Obopd since stimulation. However, better results could likely have been achieved if the foam pad and acid recipe had been placed by bull heading. The predicted injection rate was however considered low enough to achieve effective placement hence 1 .25inches Coil tubing was used.

Case History 9 (Well-19LLND)- Fig 3

This interval produces from the K3.OX Reservoir with perforated interval at 8070 — 8O8Oftah. The interval was chemically consolidated (SCON) for sand control. This well produced at 600 BOPD (dry) on bean 30/64” prior to 1992 when water production started. Since then the water production has been fluctuating reaching a peak of about 30% by 1996.

Mud Acid stimulation with foam pad via CT was carried out on this interval in December 1999. It made a gain of 240 BOPD with 35% BS&W on bean 30/64”. In September 2001 however, the new HV-HF acid system treatment with foam pad via CT brought this interval to production at oil gain of only 70 BOPD with 40% BS&W on the same bean 30/64”. The gain was less than predicted (45OBOPD) because of the increased water cut.

Interval has been recommended for stimulation with the improved - high water cut well stimulation procedures pumping) and recipe- B in the future.

Case History 10 (Well-21LNIJ)— Fig 3

The interval was selected among the many recent candidates that demonstrated the results of true stimulation, scale inhibition, wettability and deep penetrating properties of HV-HF acid system. This interval produces from the E2.OX Reservoir. It was perforated at 9012 — 9O57ftah. This well produced at 2500 BOPD (dry) on bean 40/64” and gradually declined to an average rate of 1500 BOPD on bean 52/64”. This interval was stimulated with HF-HV Acid System via Coil Tubing in November 2001. A gain of 2600 BOPD was achieved from the HF-HV Acid System treatment. Treatment payback was just five days. Even after seven months (November 2001 to June 2002), the interval is still maintaining low skin and high oil rate of - 2 and 4500BOPD respectively.

CONCLUSIONS

1. High rate pumping and foam pad diversion are effective for stimulating high water cut wells.
2. Proper recipe selection and pumping sequence are critical to successful stimulation.
3. Field Case Histories in the Niger Delta show that the HV-HF acid system described in this paper are successful with the stimulation of high water cut wells. The wells so stimulated have generally sustained productivity over long periods.
4. This technique used with the HV-HF acid system has helped change the age long negative mind set on risk of stimulating high water cut wells and has significantly increased the candidates selection scope to include high water cut wells.

5. Five wells (with high water cut ranging from 20% to 60%) previously treated with Mud Acid and re-treated with the HV-HF Acid System, show over 300% economic and technical improvement using the HV-HF Acid System over the previous Mud Acid treatments.

Equations

Q_{max} = 4.917*106kh(Maxp - P)Il.tB_0 ln(re/rw)+ S 1

FG = ((v / 1-v) * (By— P) + P) / depth(ft) 2

B = pgh = 1.1(psi/ft)*depth(ft) 3

v = 0.25 - 0.26 (Niger Delta) 4

Maxp = FG * SF * TVD 5

MSTP = Maxp - Ph ÷ Pf 6

SF = 0.8 - 0.9 7

B_y = Overburden stress

Bean = Choke

BHST = Bottom Hole Static Temperature

BOPD = Barrels of Oil per Day

BSW = Base Sediment and Water (%)

CHGP = Cased Hole Gravel Pack

cp = Centipoises

FG = fracture gradient

GOR Gas Oil Ratio GPF = Gallons per foot

h = Formation thickness

HCI = Hydrochloric acid

HF = Hydrogen fluoride

HF Acid= Hydrofluoric acid

IGP = Internal Gravel Pack

k = Permeability of formation

Maxp = Maximum allowable pressure

rnD = Millidarcy

MD = Measured depth

NH4HF2 = Ammonium bifluoride

P = Pore pressure

Ph = Injection fluid hydrostatic pressure

Pr = Pipe frictional pressure from charts

P1 = Productivity Index

Qrnax = Maximum production rate

re = Drainage radius

r = Welibore radius

SF = Safety factor

S = Skin value due to damage

THP = Tubing head pressure,

Tr = Traces

TVD = True vertical depth

v = Poisson's ratio

p = Density of rock matrix .

= Viscosity of reservoir crude.

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SI Metric Conversion Factors

ft x 3.048* E — 01 = m
°F(°F-32)/I.8 =
in. x 2.54* E + 00 = cm
psi x 6.894 757 E + 00 = kPa
gal x 3.785 412 E —03 = m3
mile x 1.069 E + 00 = km
*Conversion factor is exact

Table 5 – Economic Criteria Comparison (Old and New Approach)

CASE	ECONOMIC CRITERIA									
	Payback Time - crude @20$/bbl (days)		360 Day Incremental Production BOPD x 10^3		360 day Cumulative Incremental Revenue x 10^3 dollars		Total Job Cost $ (job cost plus other associated cost)		Unit Technical Cost (dollar/barrel of oil per year) assumed 36% decline rate	
	Old (with Mud Acid)	New (with HF Acid)	Old (with Mud Acid)	New (with HF Acid)	Old (with Mud Acid)	New (with HF Acid)	Old (with Mud Acid)	New (with HF Acid)	Old (with Mud Acid)	New (with HF Acid)
1	19	2	90	1296	1800	25920	97000	112000	1.68	0.14
2	23	6	108	720	2160	14400	138000	255000	2.00	0.55
7	24	13	101	234	2016	4680	136800	174000	2.12	1.16
8	17	10	86	115	1728	2304	87800	64200	1.44	0.87
9	22	32	72	25	1440	504	87000	44200	1.89	2.74

Table 6 – Economic Success Indicators

CASE	Payback Time - crude @20$/bbl (days)	360 Day Incremental BOPD x 10^3	360 day Incremental Revenue x 10^3 dollars	Total Job Cost $	Unit Technical Cost ($/bopa)
3	13	252	5040	177000	1.1
4	8	443	8856	208800	0.74
5	10	328	6552	189600	0.90
6	5	1368	27360	363000	0.41
10	5	1296	25920	351000	0.42

Table 7 – Treatment Performance.

	PRE – TREATMENT PERFORMANCE				POST – TREATMENT PERFORMANCE				
CASES	DATE	BEAN /64"	NET OIL BOPD	BSW %	DATE	BEAN /64"	NET OIL BOPD	BSW %	Comments
1	JUNE 90	44	235	0	APRIL 93	72	662	4	Mud acid treatment
	MAR. 98	72	632	4	JULY 98	64	4155	0	HV-HF acid treatment
					MAY 02	72	4100	0	Present rates
2	APRIL 96	56	1535	4	OCT. 96	56	1670	26	Mud acid treatment
	FEB. 97	60	1569	26	JULY 98	60	3990	0	HV-HF acid treatment
					MAY 02	60	3880	0	
	MAY 98	60	WELL QUIT						Present rates
7	DEC. 96	20	336	10	MAR. 99	20	633	10	Mud acid treatment
					JUN. 01	20	344	25	
	JUN. 01	20	344	25	JUN. 01	20	990	0	HV-HF acid treatment
					FEB. 02	[illegible]	850	5	
8	AUG. 92	32	WELL QUIT		MAY 93	[illegible]	240	0	Mud acid treatment
	MAR. 01	32	774	20	MAY 02	32	1100	22	HV-HF acid treatment
9	SEPT. 94	30	200	10	DEC 94	30	400	30	Mud acid treatment
	MAR. 01	30	655	37	MAY 02	30	720	40	HV-HF acid treatment

Table 8 – Treatment Performance Other HV-HF Acid System.

	PRE – TREATMENT PERFORMANCE				POST – TREATMENT PERFORMANCE			
CASES	DATE	BEAN /64"	NET OIL BOPD	BSW %	DATE	BEAN /64"	NET OIL BOPD	BSW %
3	NOV . 01	48	0	QUIT at 58	MAY 02	24	700	18
4	OCT. 01	52	490	47	MAY 02	40	1400	40
5	OCT. 01	52	570	50	MAY 02	52	1900	41
6	NOV. 01	44	2260	30	MAY 02	28	1630	28
10	NOV. 01	52	1500	0	MAY 02	52	5100	0

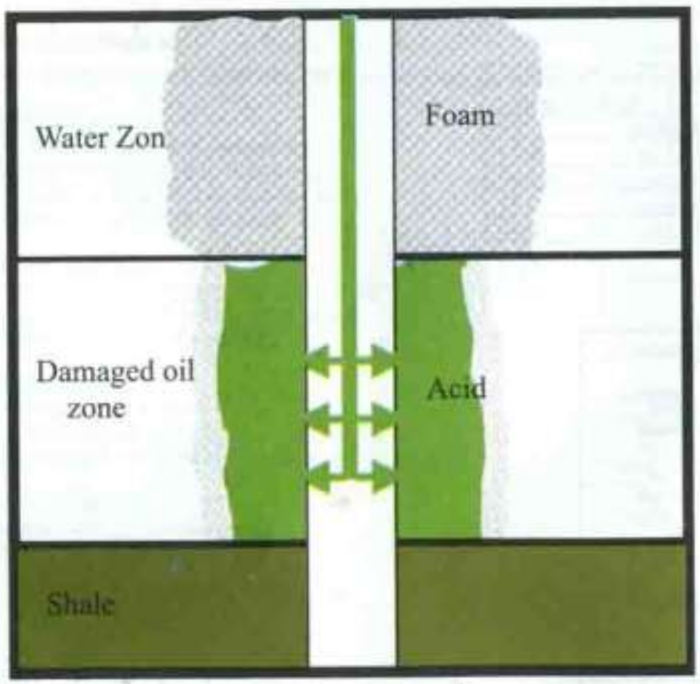


Figure 1 Stable foam diversion

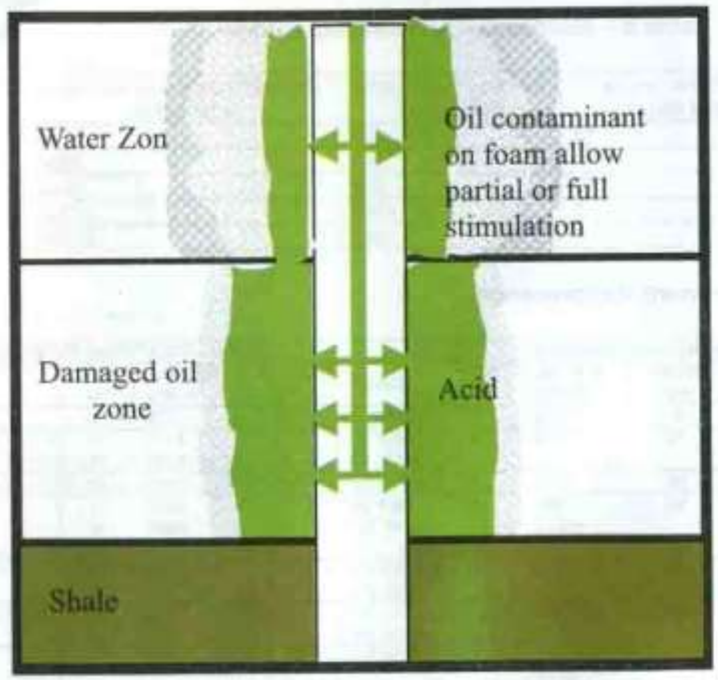


Figure 2 Contaminated foam - partial or no diversion

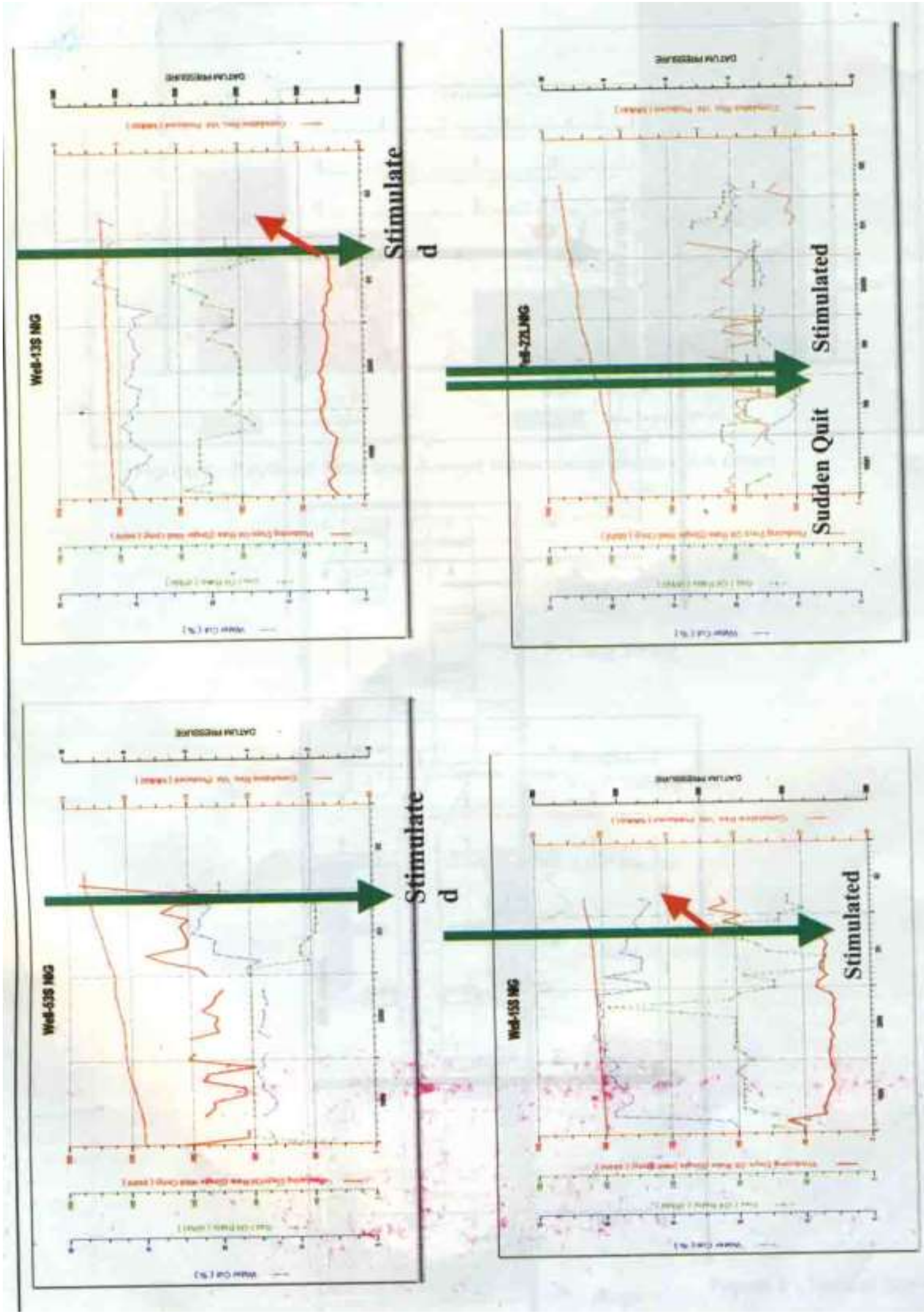
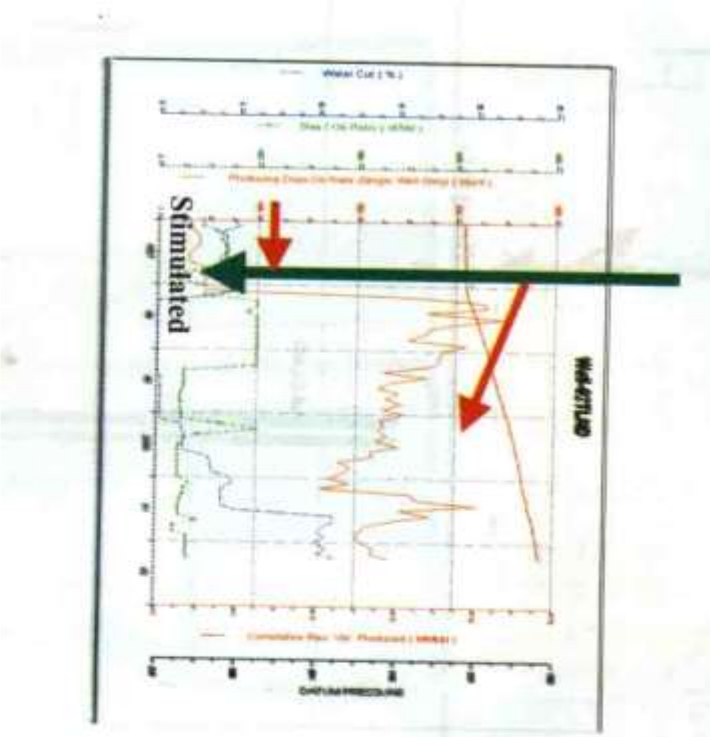
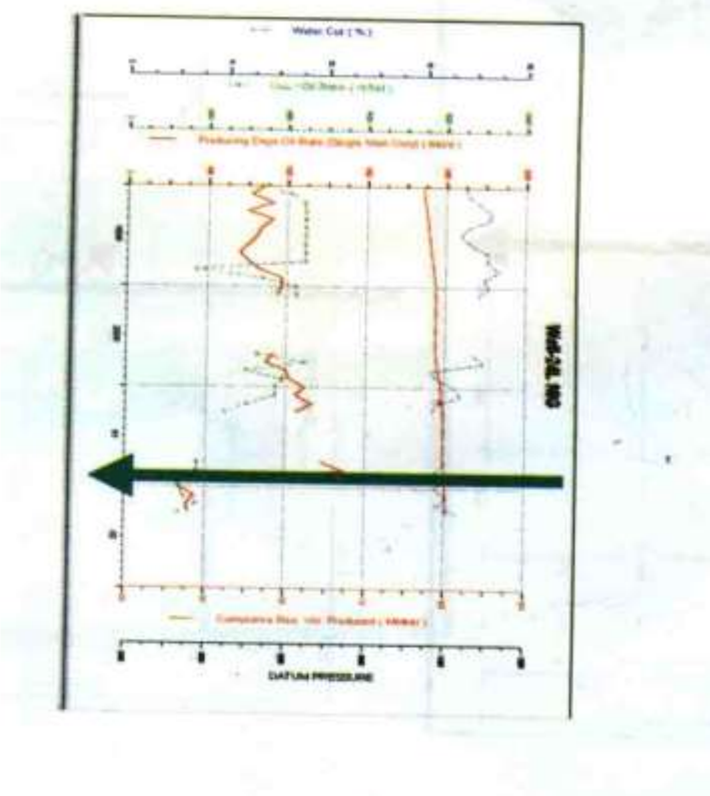


Figure 3 - Production plots


Stimulated
DATUM PRESSURE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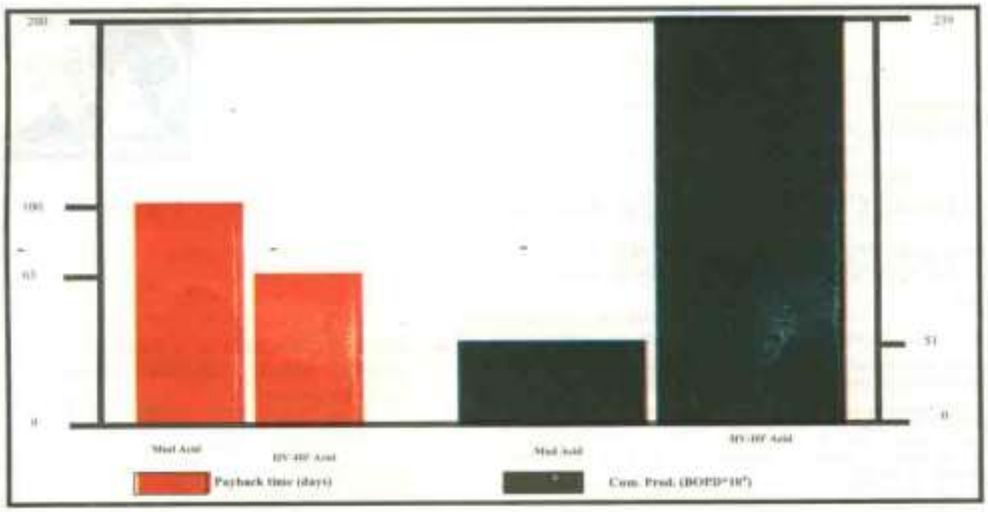

Figure 4 - Payback Time and Annual Incremental production Chart

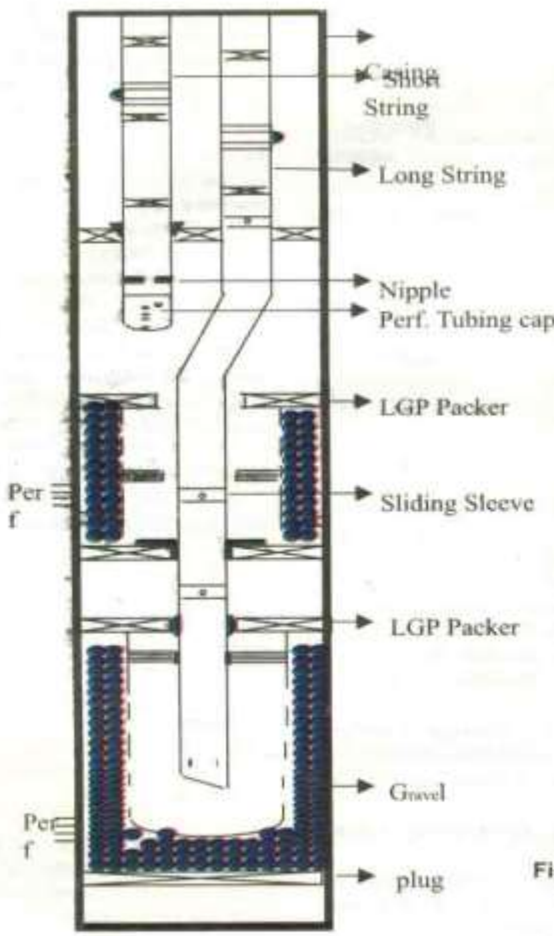

Figure 5 - Typical Status