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GAS LIFT: PRODUCING MARGINAL FIELDS USING HIGH GAS RESERVOIR PRESSURE AS CONTINUOUS GAS SOURCE

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ABSTRACT
Gas lift is one of the eight artificial lift technique applied to enhance the productions of oil wells (natural flowing or dead due to higher hydrostatic pressure over the reservoir pressure required to overcome it). The two major disadvantages of gas lift are; continuous source of high pressure gas and work over of, wells to install side pockets mandrel(s) for gas injection especially where gas lift was not initially planned before well completion. In Nigeria the above constrains are obvious especially when considering gas lifting of marginal, depleted fields and water logged wells. The paper presents a case where this class fields have been economically produced considering the presence of map gnus! High pressure gas reservoir as continuous gas source and use of wire line operated perforator and wire line retrievable pack off tubing assembles. This process could be used to sustain optimal production of similar fields to abandonment without necessarily leaving sustainable oil and gas reserves in place.

INTRODUCTION
There usually comes a time in the natural life of an oil well when the reservoir pressure can no longer push the reservoir fluids to the surface. As a result, the well usually 'loads up" and dies, in most cases leaving a lot oı otherwise recoverable reserves unproduced. Sometimes, they may just flow intermittently. In cases like this, after certain economic factors have been considered, secondary recover. Methods are sometimes considered in an attempt to keep the wells flowing. There are several different kinds of artificial lift methods as discussed by Brown and Clegg et al as:

(1) Sucker Rod Pumping,
(2) Progressing Curtly Pumping,
(3) Electric Submersible Pumping,
(4) Hydraulic Reciprocating Pump,
(5) Hydraulic Jet Pumping.
(6) Continuous Flow Gas Lift,
(7) Intermittent Gas Lift
(8) Plunger Lift,

The selection of the most suitable artificial method is pertinent to the overall profitability of an oil well and is dependent on such factors as flow rates, well location, corrosion, sand production, paraffin, scale deposition, availability of gas, cost and others. In the United States where most of the wells statistics are current. It has been recorded that the three most popular artificial lift methods are:

- Sucker Rod Pumping = 85%
- Continuous Flow Gas Lift = 12%
- Electric Submersible pumps = 3%

In general, sucker rod pumps are mostly installed in low rate wells (< 50 bbl day) and are used mostly on land locations where space limitation is not usually a problems.. Gas lift methods on the other hand re used in medium to high producers (50bbl/day - 5,000bbl/day). In offshore locations where space is a constraint, Gas lift and Electric Submersible Pumping methods are usually suitable.

In Nigeria, most of the marginal producers usually flow more than Sobbl/day, in fact wells that produce less than this are usually viewed as being uneconomical to produce. Some marginal wells may even make up to (4,000-5,000) bbl/day, probably with high water cut. Secondly these wells are usually associated with high water cuts, since according to available data, over sixty percent (60 %) of the reservoirs in Niger delta are water driven. Given these prevailing factors: high flow rates, land and offshore locations, sand production, high water cuts, gas lift is the artificial lift method of choice for the wells in Nigeria from the options.

WHAT IS GAS LIFT

This method of artificial lift is well covered in the literature. Gas lift may be summarily defined as a method whereby a stream of gas bubbles is introduced into a well fluid column to aerate it and lighten the column so that the reservoir pressure can push the well fluids to surface at an economic rate. Gas lift was first applied to an oil well in 1864, using single-point injection. This principle was followed until 1929 and aided in the production from very large fields. In a conventional gas lift installation, preferably done during the initial completion of the well, side-pocket gas lift mandrels are run with dummy valves with the completion string. The dummy valves are later replaced with live gas lift valves when the well is ready to be produced by gas lift.

ADVANTAGES AND DISADVANTAGES OF GAS LIFT

Advantages and disadvantages of gas lift in different applications have been discussed widely in the literature as follows:

ADVANTAGES:

• Low investment for deep wells,
• Cost efficient in high GOR wells,
• Low operating cost for high sand producing,
• Flexible in meeting changing producing conditions,
• Adaptable in deviated holes,
• Capable of lifting large fluid volume,
• Surface equipment can be centralized.
• Valves can be retrievable.

DISADVANTAGES:

• Requires a continuous source of makeup gas,
• High operating cost of makeup gas if purchased,
• High operating cost with corrosive gases,
• Thick producing levels make it impracticable to maintain low producing levels,
• System requires flack pressure of producing (can't be pumped off),
• Gas lift not possible if mandrels are not installed during the initial completion (needs a major work over),
• Safely hazard handling high pressure Gas,
• Casing condition must withstand high lift Pressure (Corrosion-Big Problem).

SINGLE POINT INJECTION AND HIGH PRESSURE KICK-OFF:

According to Shotbolt17. "Conventional gas lift technology has only relatively low continuous-flow gas pressure available, and it depends on gas lift unloading valves for startup. These valves are located at a series of levels or stations down the well (production tubing) such that gas in the annulus can initially enter the tubing liquid at the highest level ". Figure 1 illustrates a typical design where 5 valves are required to unload a well to about 8000 ft using 1800 psi surface pressure as against -a single valve with 3000 psi surface pressure. Under a normal operating conditions, gas is injected through one valve. Thus the number of side packet mandrels/valves used depends on the available surface pressure and the optimal fluid level to lift.

Figure 2 illustrates the two major controls for an optimal gas lift system. These are the gas lift choke (variable) and the down hole orifice. Gas lift mandrels / dummy valves are normally run during the initial completion of the well. However, there are cases whereby this may not have been done. If these wells need to be gas lifted, a full work over has to be carried out to install them. The production tubing has to be pulled and rerun with gas lift mandrels. This may not be economically justifiable especially if only marginal recovery is expected from the field. An economically viable alternative to a full work over is the installation of pack-off assemblies in the production tubing using wire lines.

GAS LIFT PACK-OFF SYSTEM INSTALLATION

A pack off system is primarily designed to isolate a hole in the tubing. In a gas lift pack off installation, a hole is perforated in the tubing with a Kenly Perforator or an, other type of perforator run on wire line. A pack-off assembly which Consist of the lower pack-off, conventional gas lift mandrel with a valve installed and an upper pack-off equipment is run to isolate the bole made in the tubing. This entire package is designed to provide safety and control for the gas that will be injected into the well when it is placed o gas lift and it is entirely installed with wire line (see Figure 31. When the pack-off assenibl3 is satisfactorily installed in the well, gas injection ma, be initiated to unload the well. The valve is placed at an optimum depth so that the available gas pressure will be used to lift the lye!1 from the deepest possible position. A time saving option if done safely is to unload the well after perforating the tubing and the Perforator is retrieved from the well and before the installation of the pack off assembly. After the well is unloaded and kicked off, gas injection may then be optimized by ensuring that the proper amount of gas is injected for the desirable production rates. Gas lift optimization techniques have been discussed by Kanu 7,8,9,10 and is fully applicable to single point gas lift injection wells with pack-off installations.

SOURCING HIGH PRESSURE GAS FOR CONTINUOUS GAS LIFTING

There are two major sources of high pressure gas for gas lifting system. These are; corn pressing of produced as from pressure range of 2O-2O psi to about 1000-2000 psi required for injection. This process could he termed recycle gas process. The other source is to produce a high pressure gas reservoir (already compressed). Strip it of a fluid at surface using high pressure separator, before

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injection. The economies associated with the sources depend the oil production environment of the field under consideration. For major oil fields that requires high volume of gas. It is more economical to install gas compressor with the associated facilities especially, in a land location where space is not a limiting factor. However, where the field is marginal and where wells may be drilled on clustered area. ii is economical to source gas from any gas reservoir that transverses the field. It should be noted that some of the gas reservoirs intercalated in the oil field will never be economical to produce before or after the abandonment of the oil field. Secondly this marginal field may not be viable to produce with any other secondary recovery method. Thus substantial oil and the gas reserves may he left in place rather than producing both by using the gas to lift the oil at optimal and economic conditions.

NIGERIAN CASE

In the Nigerian case, all the advantages of gas lift are fully appreciated and integrated into the secondary recovery systems. However, a review of Nigerian reservoirs and production environment reveal some unique factors that may be used under certain circumstances to convert some of the disadvantages of gas lift into significant economic benefits. Such factors are;

(a) Most oil fields in Nigeria have water drive reservoirs,

(b) Most wells cut through several hydrocarbon pay zones in which some are large/high pressure gas sands exist,

(c) Some so called "Marginal" wells can still be produced at economically justifiable rates even with the high water cuts,

(d) Ample availability of non corrosive high pressure associated gas at minimal cost.

Many old wells in Nigeria were not completed nub gas lift mandrels during their initial completion. These wells, lend to produce with high water cuts as the oil leg depletes and some, sells ma-, even "load" fluid iii the tubing and die. Some of the wells may leave substantial recoverable reserves in the reservoir. In cases like these, the combination of proper planning, utilization of the available resources such as gas and a careful execution of gas lift installation may result in the recovery of sizable reserves which otherwise would be abandoned. This can be done without the expense of a full work over by employing wire line techniques for the installation of gas lift pack-off system.

FIELD CASES IN NIGERIA

Several Nigerian operators have successfully adopted the Gas lift Pack-off technique to lift their wells and produced hundreds of thousands of barrels of oil from otherwise unrecoverable reserves. Texaco Overseas Petroleum (Nigeria) Company Unlimited, TOPCON, Elf Petroleum (Nigeria) Limited and Ashland Oil (Nigeria) Company Unlimited, are sonic of the companies that have used this technique with significant success.
The TOPCON program which started in 1994 is the ongoing FUNIWA and NORTH APOI fields offshore Warn, Nigeria.

FUNIWA "A"
Location: Offshore, Nigeria
Coordinate: 377,114m(E) and 35,989m(N)
Water Depth: 40 ft
Wellhead Type: Quadrapod
No. of Slots for drilling: 10
No. of completion(s): 16
No.of headers on wellhead manifold: 3
(10''Prod. 6" Test and 6" LPL)
Distance to Funiwa station: 80 m

NORTH-APOI "H"
Location: Offshore, Nigeria
Coordinate: 374,760m(E) and 39,090m(N)
Water Depth: 40 ft
Wellhead Type: Quadrapod
No. of Slots for drilling: 8
No. of completion(s): 8
No. of headers on wellhead manifold: 3
(10''Prod. 6" Test and 6" LPL)
Distance to North-Apoi station: 3.7 km
Distance to Funiwa station: 6.1 km

Firstly a feasibility study was conducted. Many options were considered as a secondary recovery process as shown in Table 1. A pilot project that cost about $1.53 million was implemented to produce about 3000 BOPD from two production jackets (Funiwa "A" and North-Apoi "H"). The project paid off in less than 2 months. The Gas was sourced from a completion that had "gassed out" on each of the two quadrapod the projects were carried out. Note that a quadrapod accommodates about 16 completions (drilled either straight, deviated or horizontal and completed either single or dual). The basic facilities provided at the quadrapod were;

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1. High pressure separator (6 mmscf and 600 stb),
2. Gas distribution manifold
3. Hook-up lines with Surface Gas Injection rate

This is illustrated in Figure 4. This could be compared with about $34.3 million required to recycle produced gas through compression and distribution system. This excludes the associated overhead cost of equipment attendance and maintenance. Initially none of the wells bad gas lift mandrels since gas lilting was not planned for the field. Consequently, to condition the wells for gas injection at economic rate, the pack-off system was adopted. However for subsequent well completed or worked over, gas lift mandrels were installed. The profile of the pressure monitored during unloading process of one of the wells is shown in Figure 5a. About 2500 psi pressure was required to unload the completion fluid at the depth of 4000 ft (TVD), thereafter, the pressure dropped and stabilized at about 1000 psi injection pressure. For a normal operation, the Flowing Tubing Head Pressure (FTIIP) and the Casing Injection Pressure (UP) are supposed to form a concentric circles as shown in Figure Sb. The inner one being the TTUP while the outer is the CIP. An erratic FFHP as shown in Figure 5c, is an indication of problem i.e. caused by over injection, injection valve damage etc. The performance of some of the wells before and after they were put on gas lift is as shown in Table 2. Some that were flowing below optimal rate, increased production while some that could not initially flow due to water log, started flowing but with substantial increase in water cut. For two years since the project commenced, TOPCON has a steady 3000 BOPD incremental production due to Gas lifting.

CONCLUSION

Texaco's success is especially significant in the illustration of the fact that a proper combination of available inexpensive high pressure gas, and technique to recover a lot of oil from marginal fields. In so doing, convert some disadvantages of conventional gas lift into economic benefits in Nigeria. It is believed that this technique can be more widely applied to marginal oil fields in this country. It has highlighted the unique opportunity that exists in Nigeria where single point gas lift injection technique can be used to recover millions of barrels of oil. This is possible due to the favorable factors that are prevalent thus;

- A of pockets of high pressure gas.
- Over 60% of the reservoirs are water-drive.

- Sand production is tolerable by gas lift
- Most wells are dual production which are well suited for gas lift- In offshore locations, most wells are clustered on platform thereby providing a central location for gas lift installation for many wells.- Relatively inexpensive to install pack-off equipment.

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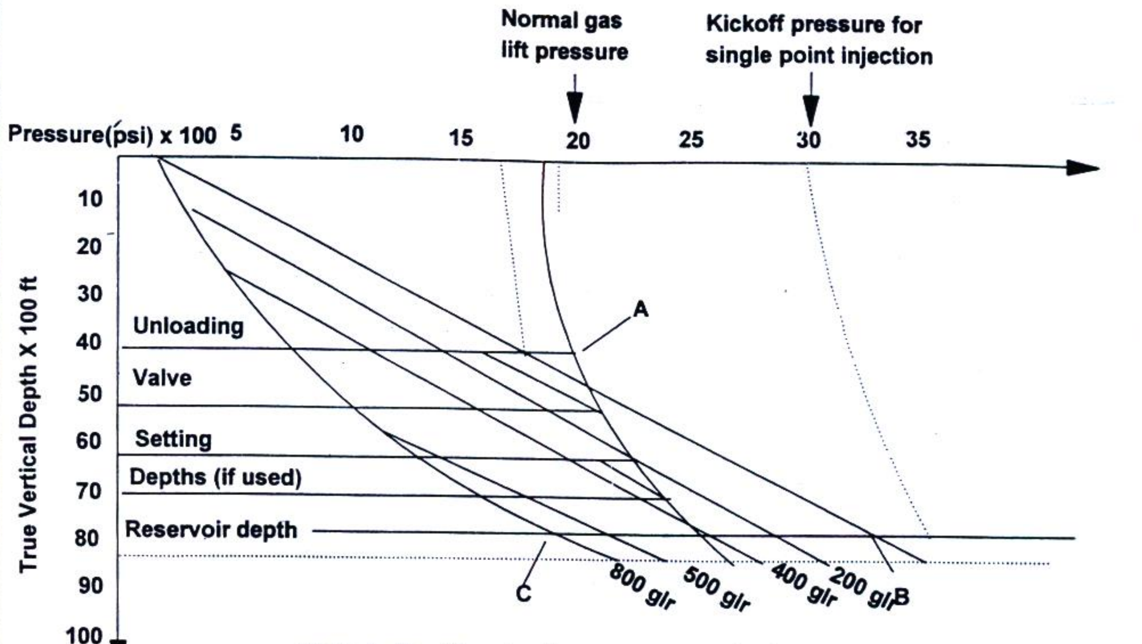

Figure 1 : Gas lift and well pressure versus depth

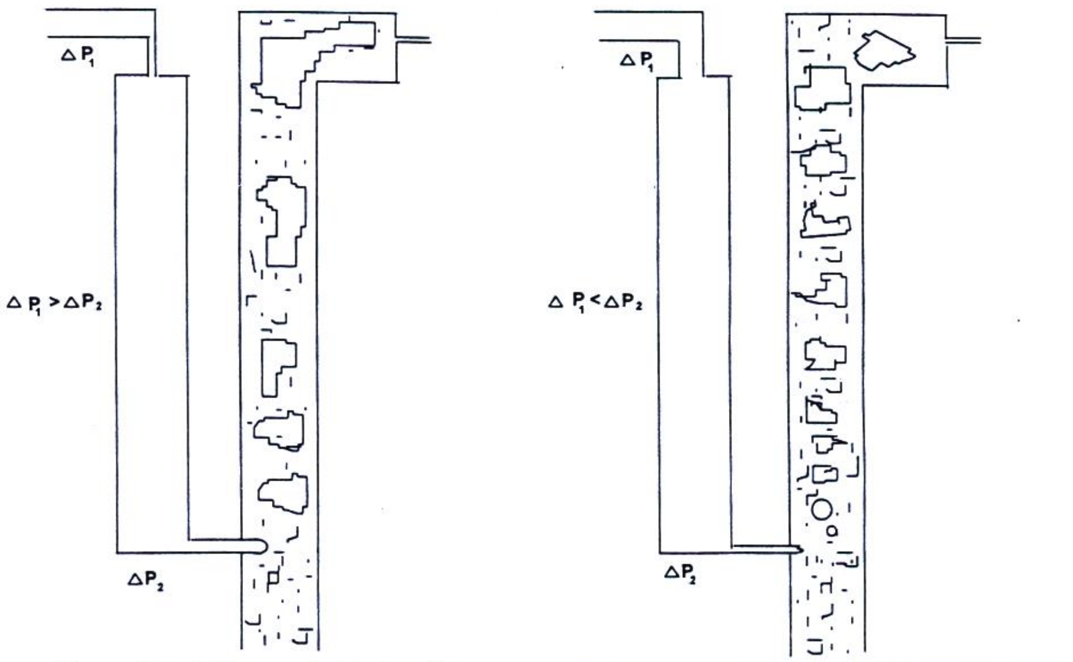

Figure 2A : Major constraint at surface choke

Figure 2B : Major constraint at downhole Orifice

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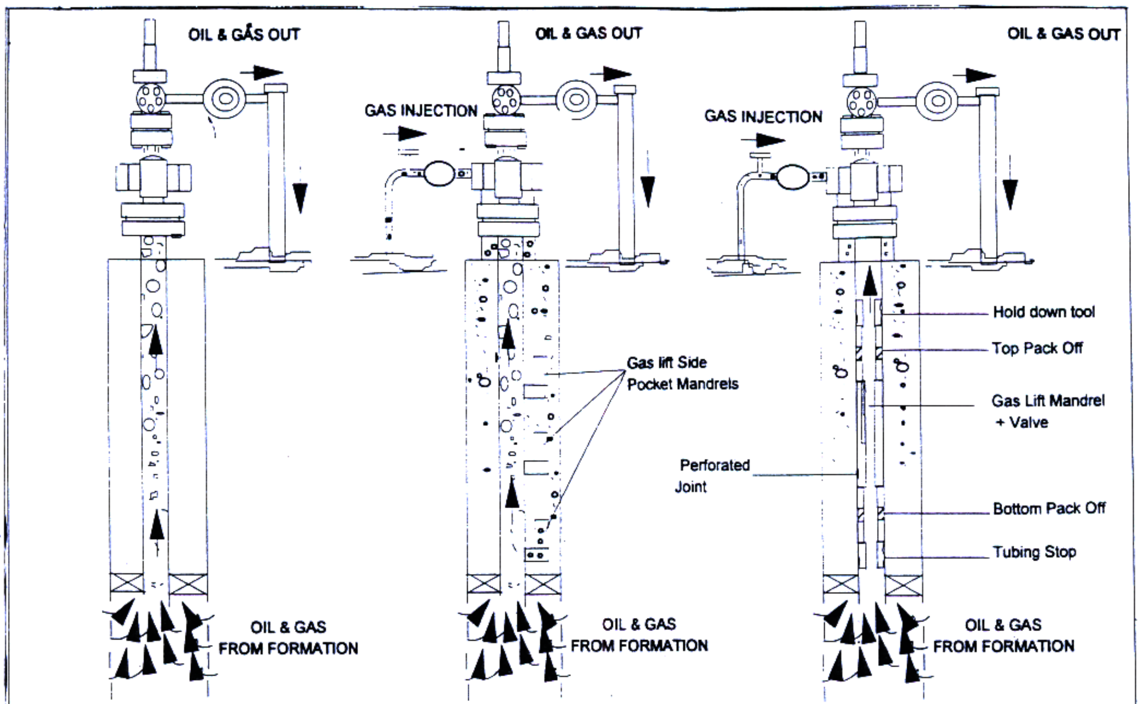


FIGURE 3
A: Natural Flow

B:A GAS LIFT WELL WITH SIDE POCKET MANDREL (CONVENTIONAL)

C: A GAS LIFT WELL WITH PACK OFF

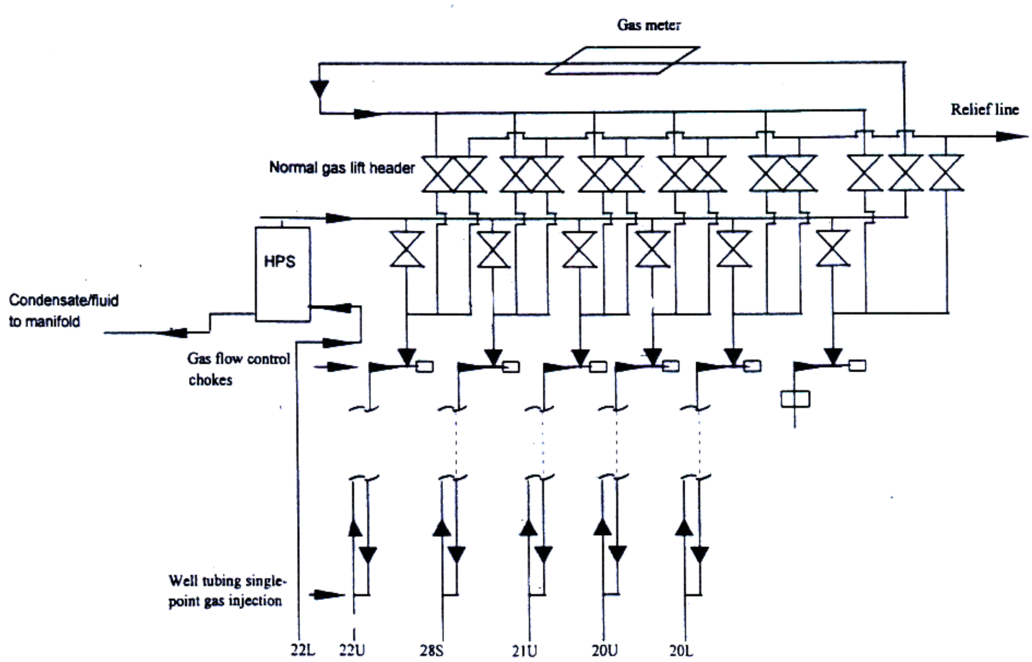
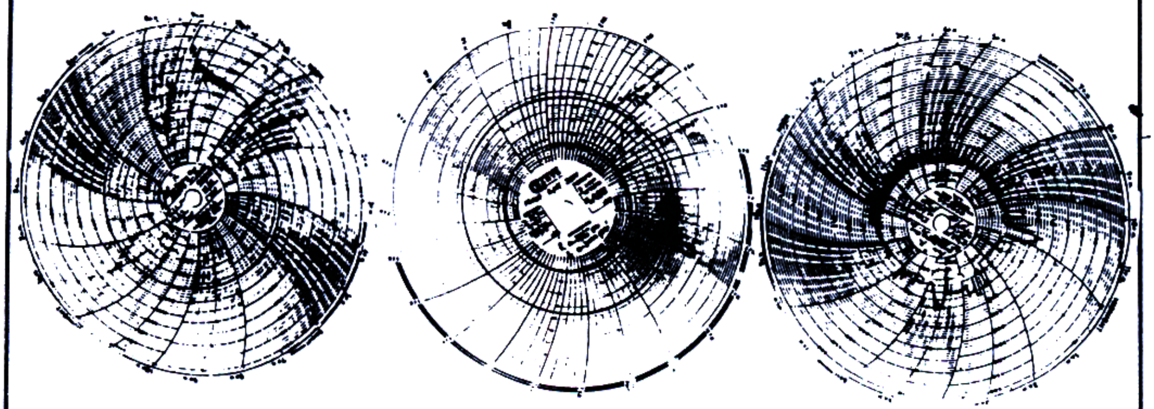


Figure 4: North-Apoi Gas Lift System

Figure 5: Pressure Monitoring Chart of Typical Well



A: Well Kickoff Profile **B: Stabilized Well Profile** **C: Unstabilized Well Profile**

Table 1: Project Options Considered

OPTIONS	FACILITIES	EXPECTED BOPD	EXPECTED COST	REMARKS
1: Conventional	1,000 psi Gas Compression for 25 Wells.	13,530	31,131,100	High overhead
2: Conventional	2,500 psi Gas Compression for 25 Wells.	13,530	34,132,000	High overhead
3:High Pressure Well	High Pressure Gas to Funiwa/ North-Apoi from Okubie Field.	13,530	8,481,000	High overhead
4:Poorboy(Gas at Well Heads)	Gas Separators at Well Heads for 25 Wells	13,530	16,444,100	High overhead
5:Poorboy-Pilot (gas at 2 Well Heads)	2 Gas Separators at 2 Well Heads for 6 Wells	2,946	1,527,300	Implemented with success

Table2: WELL DATA

LOCATIONS		FUNIWA			NORTH-APOI				Total
WELL BORE ACCESSORIES(MD-FT)		1 Lower	21Upper	25 Single	20 Upper	21Upper	22 Upper	28 Single	
DHSV		251	253	288	223	217	198	299	
Upper Tubing Stop		4246	4556	.	4088	–	4240	–	
Upper Packoff		4247	4557	.	4089	–	4241	–	
Madrel		4249	4559	3975/4600/4947/5325	4091	4621&5055	4243	4496&5003	
Valve and Perforation		4250	4560	4600	4092	4621	4244	4496	
Lower Packoff		4251	4561	.	4093	–	4245	–	
Lower Tubing Stop		4252	4563	.	4095	–	4247	–	
Sliding Sleeve		4812	7183	5796	4553	5092	7385	5830	
Dual/isolation Packer		6945	7225	5828	4586	5123	7420	5858	
No go Nipple		7058	7210	5865	4625	5146	7443	5875	
PRODUCTION RATE BEFORE GAS LIFTING	DATE	11/05/94	25/12/93	01/11/95	02/01/94	27/3/93	01/01/94	01/03/95	
	FTHP(psi)	100	180	0	120	200	0	0	
	BOPD	360	408	0	302	594	0	0	1664
	BWPD	0	612	0	204	254	0	0	1070
	BFPD	360	1020	0	506	848	0	0	2734
	GLR(scf/b)	807	543	0	403	347	0	0	
PRODUCTION RATE DURING GAS LIFTING	DATE	17/8/94	02/12/95	30/3/94	28/4/94	20/4/94	15/4/94	13/4/95	
	FTHP(psi)	150	110	170	225	500	100	150	
	BOPD	1306	560	234	686	942	632	238	4598
	BWPD	1	1306	938	686	298	2000	134	5363
	BFPD	1307	1866	1172	1372	1240	2632	372	9961
	GLR(scf/b)	425	1242	654	1114	2497	673	2852	
Incremental Oil Production BOPD)		946	152	234	384	348	632	238	2934