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Assessment of Through-Tubing Gas Lift Technology

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Abstract: Through-tubing gas lift Technology employed straddle packer assembly. It is a retrievable gas lift straddles that allows the introduction of controlled gas lift into the well without the need for an expensive work over.The aim of this researchis to assess the performance of through-tubing gas lift method using a straddle packer assembly over other method of gas lift (conventional).Natural flowing, through-tubing, and conventional gas lift scenarios were designed with the aid of three softwares in petroleum expert (Prosper, Mbal, and GAP)and their performance were compared. Using data from three wells in the Niger delta, detailed economic analysis were carried out. Results showed that through-tubing gas lift technology gave the best results with total oil production of 726,763.90bbl (well 1), 673,677.70 bbl (well 2) and 767,973bbl (well 3) while that of conventional gas lift 368,950bbl(well 1), 268,444.70bbl (well 2)and 438,797.60bbl (well 3)respectively after 10 years.Through-tubing gas lift technology is therefore ream as the best technology for sustaining high production rate and increasing revenue.

I. INTRODUCTION AND BACKGROUND

During the production life of a well, the reservoir pressure declines to a level which is incapable of transporting hydrocarbon to the surface, inadvertently needing an artificial method of lifting the oil from the reservoir. Through-tubing gas lift using straddle packer assembly was initiated in 2008 under a project called "Accelerated Gas lift program" and was implemented by Engineer Abdullahi Bashir M. in an effort to provide a temporary, simplified and quicker means of sustaining well production until the conventional, permanent gas lift facilities could be commissioned. Accelerated gas lift installation is the name employed to connote the ease with which the gas lift facility was installed since they did not require the usual rig activities for gas lift installation and since the supply of gas lift gas was achieved by the use of ¾inch instrument tubing rigged up to existing instrument air line from the production company instead of construction of a fresh network of gas lift supply pipework and headers. Work-over operation cost and well life was basis for implementing this method of gas lifting.Execution cost for this method was less than 300,000.00 USD with project execution time of one week.Gas lift is an artificial lift method, through which high pressure gas is injected continuously or intermittently into the well through annulus between the casing and tubing. Thus, resulting in the reduction of the hydrostatic pressure of the heavy column of the fluid and reducing bottom-hole flowing pressure. The purpose of gas lift is to bring hydrocarbons to the surface at a desirable quantity while keeping the bottom-hole pressure at a value that is small enough to provide high drawdown pressure within the reservoir [1]. Thus, gas lift method is where relatively high pressure gas is used as lifting agent through a mechanical process. The installation of the gas lift system is required when the pressure of the reservoir is not enough to maintain the oil production with sustainable economic return.

This system is widely applicable for oil fields where the increasing water-cut or decreasing reservoir pressure eventually causes well to cease its natural flow [2]. According to Petroleum Technology Company (PTC) the first known application experiment for lifting fluids with compressed gas in a laboratory was conducted in Germany in 1797. These forms of lift were also used in mines to lift water from mine shafts in Chemnitz, Hungary in the mid-18th century [3]. The systems used single point injection of air into the liquid stream, normally through a foot valve at the bottom of the string. In 1846 an American engineer called Cockford utilized compressed air to lift oil from wells in Pennsylvania. Twenty years later the first patent was registered in United States of America for a system called the oil ejector. Gas was injected through the annulus and into the production string via an open 'goose neck' ejector positioned into the flow stream called a 'well blower'. The system consisted of an air filled pipe connected to the tubing that blew compressed air into the bottom of the well to decrease oil density and increase well production rates (4). In Texas around 1900 gas lift with air was first used in large-scale oil field applications, and in 1920 natural gas replaced air as the lifting gas of choice because it had a lower risk of explosion. Initially gas was injected essentially uncontrolled into the bottom of the well and gas lift application was limited to shallow wells because of low injection pressures attainable [5]. In the mid-1930s the invention of a spring-operated differential gas lift valve and the development of a stepwise unloading process consisting of multiple well injection points allowed gas lift to be used for wells of even greater depths. From 1929 until 1945 about 25000 patents were issued on different types of gas lift valves that could be used for unloading in stages [6]. Some of these systems involved moving the tubing, or using wire line sinker bars to change the lift point. Others were spring operated valves. Ultimately, with the introduction of the bellows charged gas lift valve by W.R. King, gas lifting of low pressure wells with a controlled change in the surface injection pressure was achieved. King Obviously had good knowledge of valve construction when he designed this valve. He recognized the need for complete bellows protection, including an anti-chatter mechanism. The success of the King valve is evidenced by the fact that the basic principles used in the design were quickly adopted by almost all valve manufacturers and are still used with little modification up till date.However, these valves were prone to leakage and not qualified as well barriers [7]. In today's market where gas lift is predominantly used to boost (enhance) production from live pressurized wells, valve requirements has changed. In 1951, the side-pocket mandrel was developed for selectively positioning and retrieving gas lift valves with wire line. Oil production normally increases as gas injection increases. However, too much gas injection will cause slippage where gas phase moves faster than liquid.

This condition leads to reduction in oil production. Identifying optimal gas injection that maximizes oil production is the important in oil lift operations [8]. In 1955 the pressure operated valve had practically replaced all other types of gas lift valves. The first wire line retrievable gas lift valve was introduced in 1957 [9]. Kick-off valves were next employed to provide for means to closing off gas after a lower valve was uncovered. These pressure differential spring valves were operated with approximately 100psi differential pressure. This kick-off valve was the crude forerunner of modern gas lift flow valves. In the early days gas lift was predominantly used to allow dead wells to flow. . Various types of valves are used in gas lift mandrels, depending on the need of the well. The valve is called injection valve or operating valve, and normally is an orifice. The well is also equipped with unloading valves along its tubing string, which are used for well kick-off operation. These valves are typically preinstalled and deployed with the production tubing string during well completion and may need replacement later in the life of the well. This will require an intervention [10]. Placement of the mandrel within the completion string is also critical when planning for production optimization and future intervention strategy. The industry remains cautious when designing gas lift completions, tending to place gas lift mandrels in areas of the well that are considered accessible when using standard slick-line techniques [11]. A poor choice can reduce production and increase operating costs substantially. Although prudent production engineering requires continuous review of the performance of the lift method to modify operating parameters or even to evaluate changing the method, once a method is chosen, it usually stays in place. Selection of the most appropriate artificial lift method has to start when the reservoir, drilling, and completion designs and decisions are being made. This requires open communication between people in all these disciplines. Coupled to this are the production requirements and limitations in contract deliverables that must be met. Thus, obtaining good drill stem test and production rate data is the first step of method selection.

The drilling and completion scenarios then have a major impact on determining not only the best lift method but also overall well capability [12]. Many wells flow naturally without artificial stimulation when the well is first drilled. As time passes and the reservoir gas pressure drops, oil production begins to slow down, and the number of barrels of oil produced daily begins to decline. In offshore production, where every square foot of platform costs thousands of dollars to construct and space is limited, gas lift is often used when artificial lift is desired. Gas lift occupies very little space at the wellhead, and many directional 9-2 wells can be drilled close together and easily produced. This system is a common choice when lift stimulation is desired offshore [13]. Hence, through-tubing gas lift program was initiated to enhance production from existing and planned wells

II. METHODOLOGY

In this study, three existing commercial softwares in Petroleum Expert were used to simulate and assess the performance of natural flow, conventional and through-tubing gas lifted wells for production optimization. They are; Integrated Production Modeling (IPM); (Prosper, Mbal, and GAP).Natural flowing wells, through-tubing and conventional gas lifted wells were modelled for the production optimization and their performance were compared.Mbalsoftware was used for the reservoir description while prosper softwarewas used for designing the wells. Then the two softwares were incorporated into GAP software to describe the operational domain of the wells and optimize production.

Data Collection

Production history data from three wells operating in Niger Delta oil field were obtained and incorporated into Prosper Simulator to perform the simulation study of gas lift both in conventional and through-tubing gas lifted wells.

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Table 1: Collected Fluid Properties (FP) of Three Oil Wells from a Typical Niger Delta Field

Reservoir Parameters	WELL 1	WELL 2	WELL 3
Reservoir pressure	4000psi	3010psi	3000psi
Reservoir temp	210F	138 F	150F
GOR	700scf/stb	600SCF/STB	1500SCF/STB
OIL FVF	1.23RB/STB	1.31RB/STB	1.12RB/STB
Oil viscosity	0.4cp	0.6 cp	0.455cp
Bubble Point pr	2200psi	1800psi	1600psi
Reservoir permeability	300md	200md	350md
Water Salinity	80000ppm	80000ppm	80000ppm
Reservoir Thickness	250feet	200feet	150feet
Wellbore Radius	0.354feet	0.501feet	0.425feet
Oil Gravity	34API	28API	38API
Gas Gravity	0.8	0.68	0.85
Water Cut	40%	42%	50%
Well Head Pressure	600psi	400psi	360psi
Drainage Area	2500feet	1850feet	2000feet

Table 2: Gas Lift Design Parameters for Both Conventional & Through Tubing Wells

Casing Pressure Drop per Valve	50psi
Maximum Liquid Rate	10000stb/day
Maximum Gas Available	9MMscf/d
Maximum Gas while Unloading	9MMscf/d
Flowing Top Node Pressure	200psig
Unloading Top Node Pressure	200psig
Operating Injection Pressure	1500psig
Kick Off Injection Pressure	1500psig
Desired dP across Valve	200psi
Maximum Depth of Injection	7500ft
Water Cut	80%
Minimum Valve Spacing	300ft
Static Gradient of Load Fluid	0.46
Minimum Transfer dP	25%
Maximum Port Size	32 (set by valve series selection)
Measured Depth	10000ft
De Rating Percentage for	100%
Valve position	6500ft
Gas lift method	Optimum

Predicted Simulation results of Natural Flowing wells

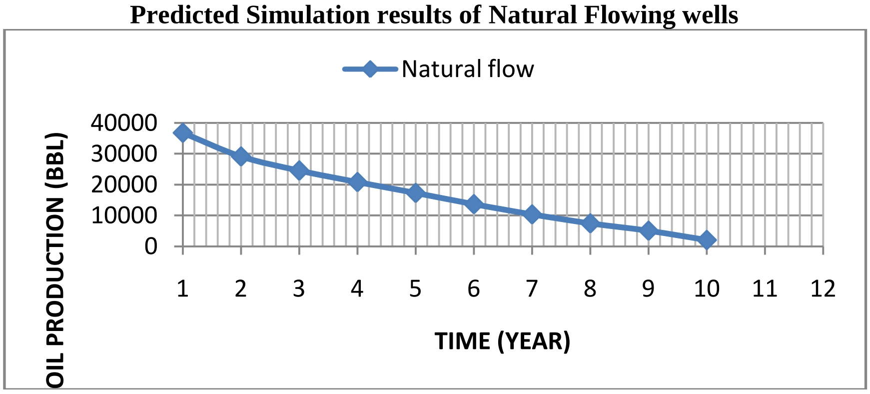

Figure 1: Oil productions on natural flow Well 1

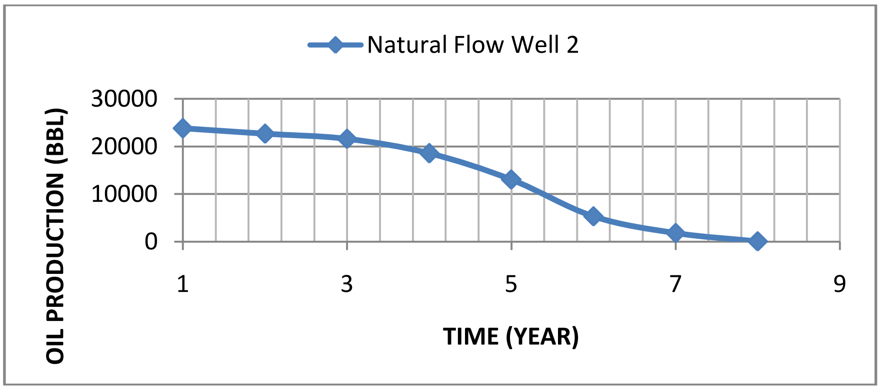

Figure 2: Oil productions on natural flow Well 2

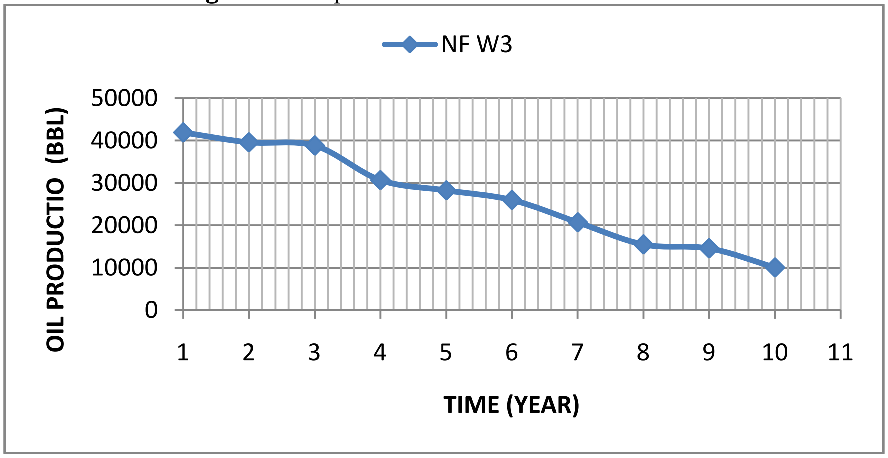

Figure 3: Oil productions on natural flow Well 3

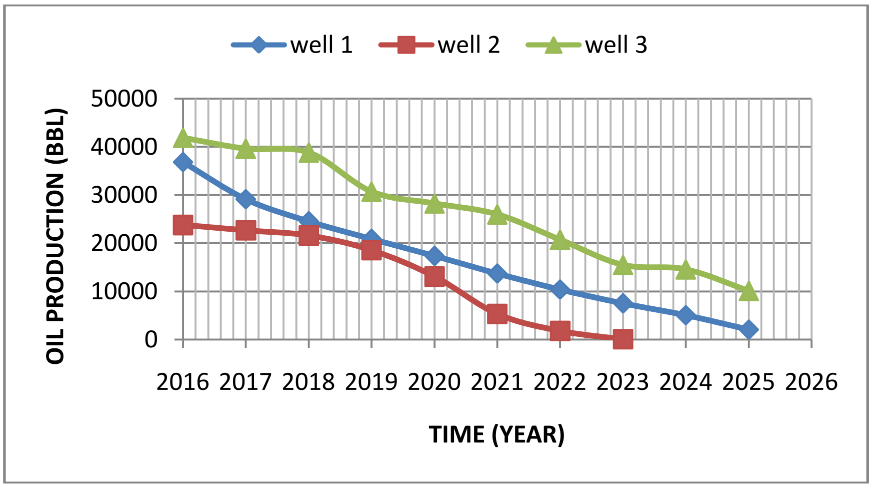

Figure 4*:* Production performance of Natural Flowing Wells

Table 3: Simulation Results Natural Flowing wells

Year	Natural flowWell 1 (bbl)	Natural flow Well 2 (bbl)	Natural flowWell 3 (bbl)
2016	36843.1	23792.3	41916.7
2017	29139.9	22673.1	39622.8
2018	24512.5	21592.6	38816
2019	20849.4	18558.5	30697.2
2020	17323	13063.4	28267.3
2021	13690.1	5300.4	25978.4
2022	10388.1	1799.2	20717.2
2023	7472.6	83.8	15486.4
2024	5046.7	0	14570.2
2025	2059.7	0	10081.8

Predicted Simulation results of Conventional Gas Lifted wells

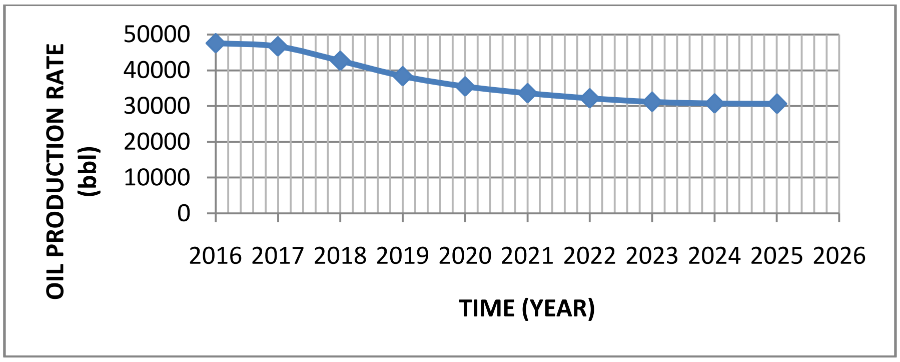

Figure 5: Oilproductions from conventional gas lift well 1

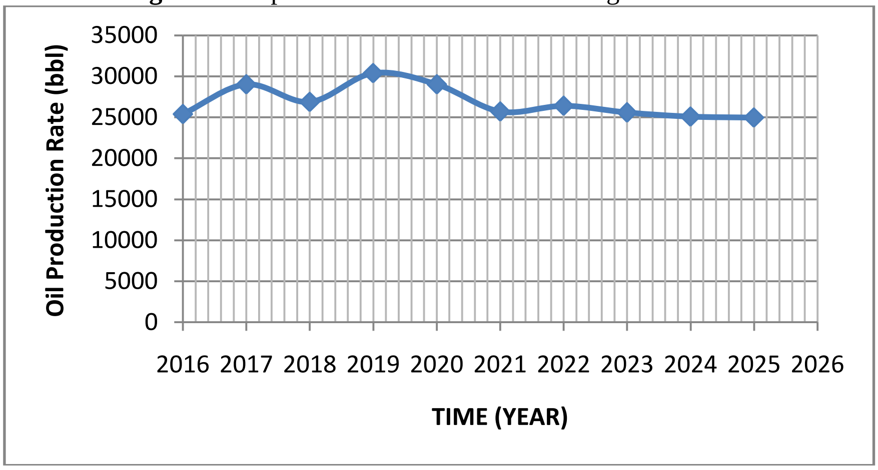

Figure 6: Oilproductions from conventional gas lift well 2

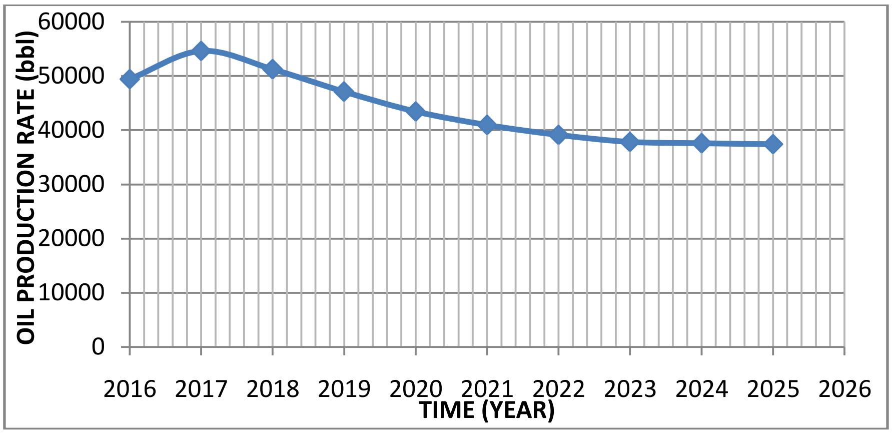

Figure 7: Oil productions from conventional gas lift well 3

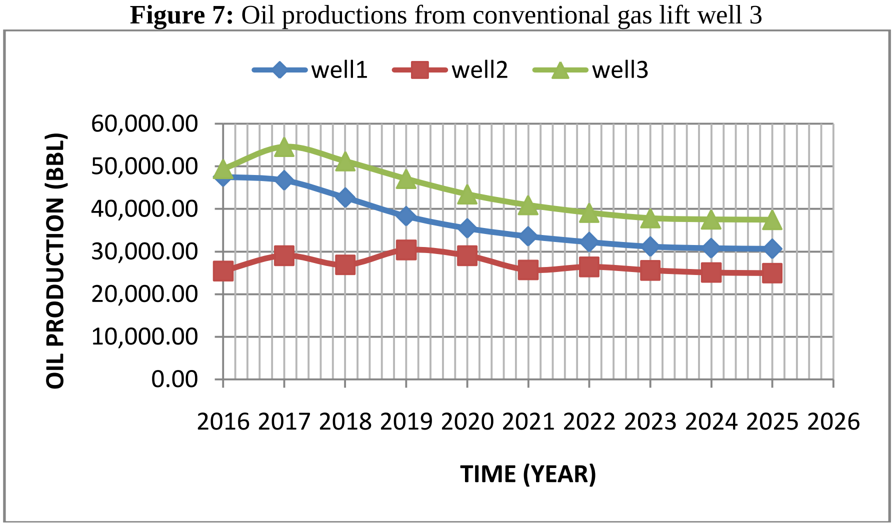

Figure 8*:* Production performance of Conventional Gas Lifted wells

Table 4: Simulation Results of Conventional Gas Lifted wells

Year	Conventional GL Well 1(bbl)	Conventional GL Well 2 (bbl)	Conventional GL Well 3 (bbl)
2016	47,570.7	25,407.9	49,451.1
2017	46,681.2	29,017.8	54,627.6
2018	42,640.7	26,880.3	51,226.9
2019	38,328.6	30,380.6	47,098.4
2020	35,475	29,023.7	43,447.7
2021	33,568.7	25,700.8	40,946.3

2022	32,181.3	26,403.4	39,141.3
2023	31,138.3	25,578.5	37,854.4
2024	30,752.4	25,094.9	37,566.6
2025	30,613.1	24,956.8	37,437.3

Predicted Simulation results of Through Tubing *gas lift* wells

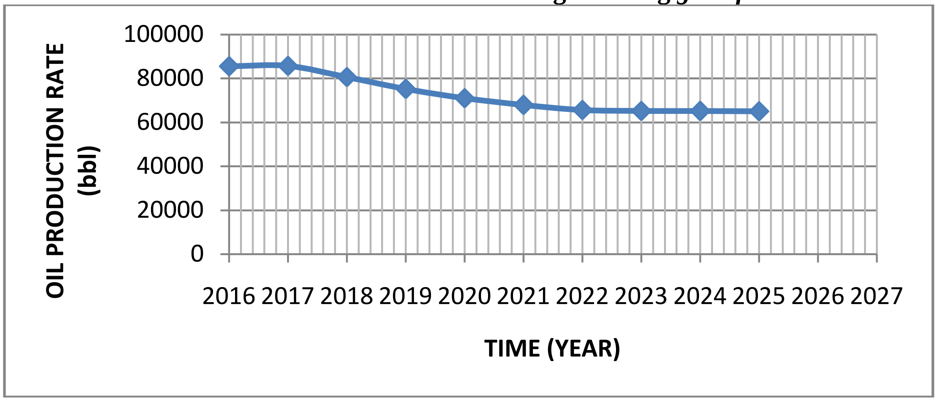

Figure 9: Oil productions from Through Tubing gas lift well 1

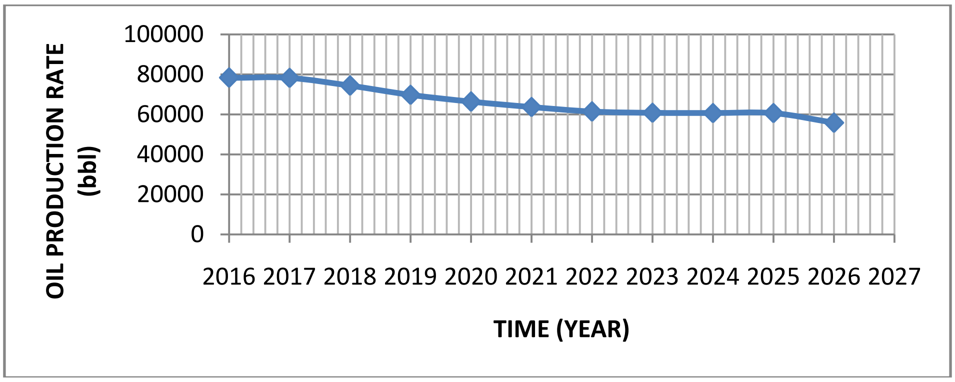

Figure 10: Oil productions from Through Tubing gas lift well 2

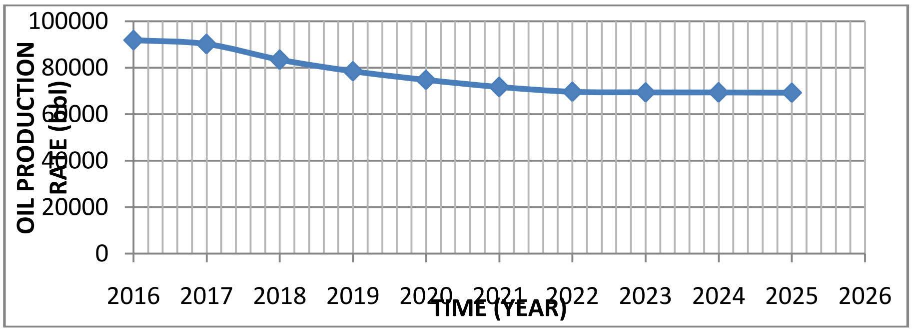

Figure11: Oil productions from Through Tubing gas lift well 3

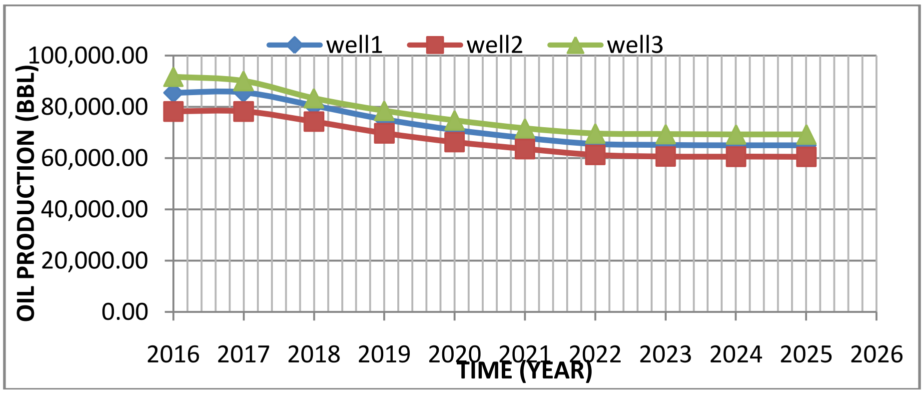

Figure 12*:* Production performance of Through Tubing Gas Lifted wells

Table 5: Simulation Results from Through Tubing Gas Lifted Wells

Year	Through Tubing Gas Lift Well 1(bbl)	Through Tubing Gas Lift Well 2 (bbl)	Through Tubing Gas Lift Well 3 (bbl)
2016	85,548.6	78,253.7	91,797
2017	85,732.5	78,239.5	90,152.8
2018	80,564.1	74,285.7	83,411.9
2019	75,126.9	69,743.9	78,491.1
2020	71,013.8	66,280	74,775.8
2021	67,888.5	63,637.5	71,684.7
2022	65,583.6	61,321.5	69,646.2
2023	65,180.7	60,704.1	69,439.1
2024	65,100.7	60,635.4	69,334
2025	65,024.5	60,576.4	69,240.3

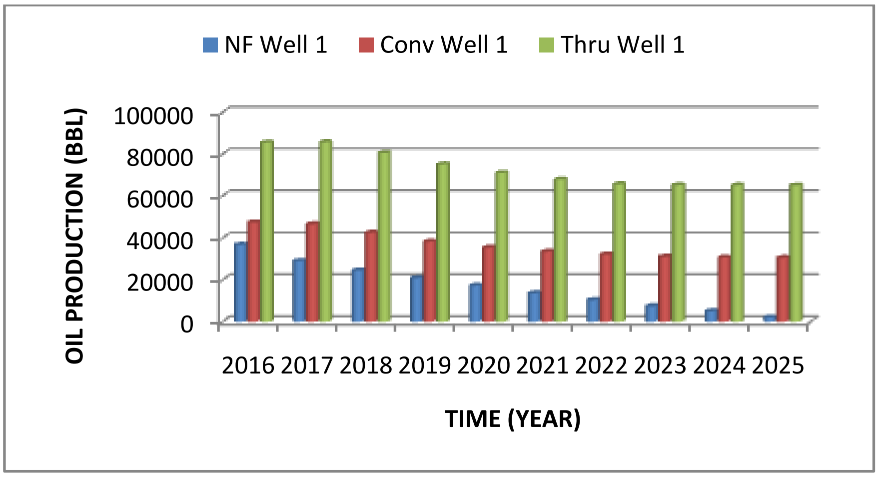

Figure 13: performance of Natural flow, Conventional and Through Tubing Gas Lifted wells 1

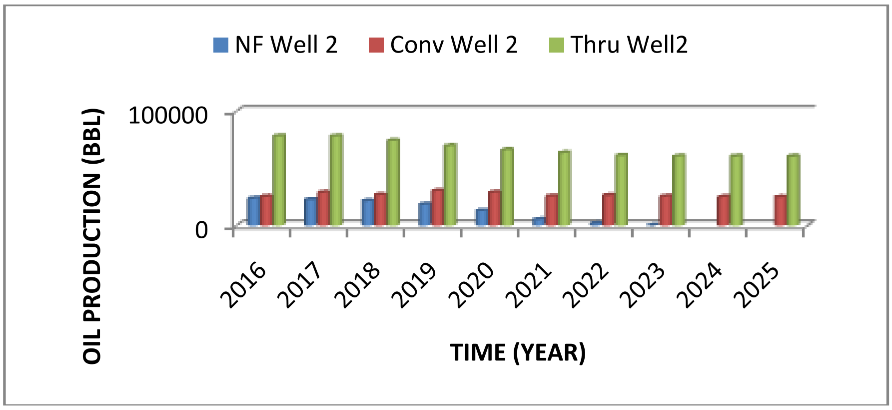

Figure 14*:*performance of Natural flow, Conventional and Through Tubing Gas Lifted wells 2

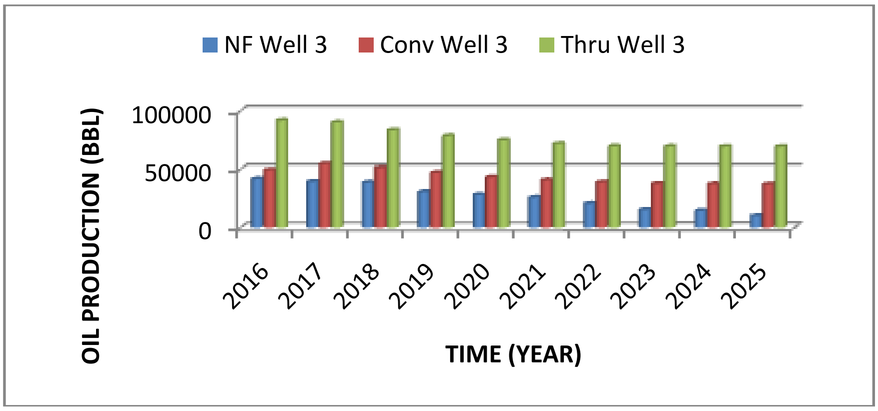

Figure 15*:* performance of Natural flow, Conventional and Through Tubing Gas Lifted wells 3

III. DISCUSSION

Figures 1 through 15 showed the results obtained from the natural flowing wells, conventional and through-tubing gas lifted wells. During the primary production of oil from the reservoir, the predominant oil recovery mechanism was the gas cap which was later supported by the active aquifer. These combined reservoir drives resulted in oil production rate of about 167,325.1bbl (well 1), 106,863.3bbl (well 2), and 266,154bbl (well 3)after ten years (Figures 1 through 4). This production wasn't profitable enough so a conventional gas lifting method was initiated.

Figures 5 through8present the results obtained from the conventional gas lifted wells in terms of oil production rate versus time. From Figure 5 (well 1), a gradual decline in oil rate was observed throughout the period of production. After 10 years of production, the oil rate declined from 47,570.7 bbl to 30,613.1 bbl (about 34% decline). In Figure 6 (well 2), production started at 25,407.9 bbl and increases to 30,380.6 bbl after four years and then declined to 24,956.8 bblafter ten years of production (about 18% decline). Figure 7 (well 3), showed the result of the oil production rate obtained from the simulation. It was observed that production started with 49,451.1 bbl and increased to 54,627.6 bbl but gradually declined to 37,437.3 bblof oil after ten years of production. An interesting observation was that the declined trend in oil production rate for the three wells changed gradually with time. However, the cost of equipment and other mechanical installations were considered to know if the project is feasible enough; by so doing the through-tubing gas lift was assumed and installed.

For the through tubing gas lift technology, the results obtained in terms of their respective oil production rate versus time for the three wells are presented in Figures 9 through 12. Figure 9 (well 1) showed the result of the oil production rate obtained from the simulation. It was observed that oil production started with 85,548.6 bbland continued with a slight decline to 65,024.5 bbl (about 24% decline) after ten years of production.In Figure 10 (well2), it was observed that production started at 78,253.7 bbland continuedwith a slight decline to 60,576.4 bbl after ten years of production (about 23% decline).In Figure 11 (well 3), production started at 91,797bbl and continued with a slight decline to 69,240.3 bbl after ten years of production (about 25% decline).

In summary, the results obtained from the production forecast showed that the through-tubing gas lifted wells gave superior production rates when compared to natural flowing wells and conventional gas lifted wells.

Economic Analysis

In making a decision whether to invest in a project, the incremental cost to complete that project should be compared with the future net revenue to be received from that project. And if the expected net revenue is greater than the project cost, the project should be completed but if not, the project should be abandoned. Therefore, in making a final decision on whether throughtubing gas lift technology increases revenue, a thorough economic analysis was carried out. However, the initial costs of the scenarios were analyzed and have given a good indication of the project magnitude. Table 5, shows the capital cost e.g. the cost until end of installation of each project. This involves cost of procurement, construction, engineering, maintenance, administration and operational cost during installation. Tables 6 to 8 showed the expected net revenues and their profits to be received from each project.

Table 5: Through Tubing and Conventional Gas Lift Estimated Cost for ten Years

For Ten Years	Through Tubing Gas Lift (10years)	Conventional Gas Lift (10years)
Item	Cost ($)	Cost ($)
Installation	1,500,000	1,800,000
Equipment	800,000	1,000,000
Running cost	1,200,000	1,401,000
Maintenance	3,000,000	5,000,000
Sum	**6,500,000**	**9,201,000**

Assuming $40 per barrel of crude oil, then the estimated cost for ten years is tabulated as shown in Table 6.

Table 6: Total Estimates of oil revenue for Natural flowWells

Items	**Natural flowWell** 1	**Natural flowWell** 2	**Natural flowWell** 3
Oil rate (bbl)	167,325.1	106,863.3	266,154
Revenue ($)	6,693,004	4,274,532	10,646,160
Installation/operating	6,000,000	6,000,000	6,000,000
Gross Profit ($)	**693,004**	**-1,725,468**	**4,646,160**

Table 7: Total Estimates of oil revenue for Conventional Gas Lifted Wells

Items	Conventional GL Well 1	Conventional GL Well 2	Conventional GL Well 3
Oil rate (bbl)	368,950	268,444.7	438,797.6

Revenue ($)	14,758,000	10,737,788	17,551,904
Installation/operating	9,201,000	9,201,000	9,201,000
Gross Profit ($)	**5,557,000**	**1,536,788**	**8,350,904**

Table 8: Total Estimates of oil revenue for Through Tubing Gas Lifted Wells

Items	Through Tubing Gas Lift Well 1	Through Tubing Gas Lift Well 2	Through Tubing Gas Lift Well 3
Oil rate (bbl)	726,763.9	729,363.4	767,972.9
Revenue ($)	29,070,556	29,174,536	30,718,916
Installation/operating	6,500,000	6,500,000	6,500,000
Gross Profit ($)	**22,570,556**	**22,674,536**	**24,218,916**

IV. CONCLUSION

Thorough consideration of the production profile, economic analysis and desired rate of natural flowing wells, conventional and through-tubing gas lifted wells were performed for production optimization to compare the most suitable gas lift method for the wells in the Niger Delta oil field, the following conclusions were drawn:

[1]. Both conventional and through-tubing gas lift gave a large increase in production when compared but through-tubing gas lift is superior to conventional gas lift.

[2]. This study also reflects the economics of using through tubing gas lift as it is relatively cheaper due to the fact that it about sustaining and increasing revenue.

[3]. Through tubing gas lifted well is the best both in terms of production increase and gross profit which are the major factors in any investment decision making.

[4]. The volume of gas injected is a critical factor in the cumulative oil that can be potentially be produced, and as such a special consideration should be given to the volume injected alongside wellhead backpressure and equipment costing.

[5]. Through tubing gas lift technology allows reinstatement of controlled gas lift in wells where existing system has failed.

[6]. Field for which through tubing gas lift is to be implemented should have a well layout pattern for effective gas distribution down the reservoir. Hence, the through tubing gas lift technology is capable of improving oil recovery.

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