

Analysis of Crude Oil Production Using Gas Lift

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ABSTRACT

Gas lift is used to increase production by reduction in the density of the oil column in the tubing, reduction of the flowing bottom-hole pressure which is affected by the hydrostatic pressure of the fluid column and by providing external energy to the oil. In this study an oil field in the Niger Delta was used as case study; it has a production life span of over ten years with characteristics such as high gas-oil ratio (GOR) and high reservoir pressure which makes gas lift suitable for optimizing the wells. The aim of this study is to select the gas lift method suitable for optimum production in the wells using the production modelling softwares PROSPER, and GAP. Simulation studies were conducted using data from two wells in the oil field. The performance of continuous and intermittent gas lifted performance on two wells were compared. The results indicated that continuous gas lift system will be suitable for a well that has high flow rate and high GOR. Also, intermittent gas lift system will be suitable for a well that has lower reservoir pressure and low productivity. Sensitivity analysis of water cuts, gas injection rates and well head pressures were carried out to investigate how the wells will respond to changing operating conditions such as increasing water cut, increasing gas injection rates and increasing well head pressures in the future.

Keywords: Gas lift, Gas-Oil Ratio, Continuous and Intermittent Gas Lift System, Sensitivity Analysis.

INTRODUCTION

Production of crude oil from the well can be achieved with the natural energy of the well at its early life, when the natural drive is most active and crude oil is produced from the reservoir at commercially viable rate. Factors most responsible for this are the gas cap, solution gas, and water drive. A well produces with a combination of these drives at a particular time; subsequently as production progresses, the reservoir natural energy depletes leading to reduced reservoir pressure and bottom hole flowing pressure (BHFP) that accompanies the oil to the surface, increased water cut with resulting decrease in gas-liquid ratio (GLR). Increased pressure drop and water cut are often experienced in mature fields that has been in production over a period of time. Other challenges that could also affect decline in production rate are inappropriate perforation method, inadequate design of the well production system and inept management of a well. At this point where the well is unable to produce at its own natural energy and at economical production rate, a best known option is the application of artificial lift method for enhanced oil recovery (EOR). Artificial lift systems are designed to assist reservoirs that may not be able to produce its formation fluids using its own natural drive at

economical rates for optimal production. A good percentage of the producing oil wells require forms of artificial lift for increment in the flow rate of the well fluids where the reservoir has insufficient energy to produce naturally at economical rates or to achieve an early production from a well where the well fluid is very viscous. The goal of artificial lift system is to maximize profit or improve financial performance. Operators of oil wells are required to know the most suitable artificial lift system to incorporate in their wells to optimize production to ensure minimal capital and operating cost.

Gas lift system has been identified as the most commonly used artificial lift systems for EOR. During the gas lift process, very high pressured gas is passed down into the wellbore through the gas lift valves, which is positioned inside the gas lift mandrels, through the annulus, into the tubing strings. The gas undergoes expansion in the tubing thereby causing a reduction in the reservoir pressure, density and column weight of the fluid flowing from the reservoir which allows the well to flow properly. There are two major types of gas lift namely; continuous and intermittent gas lift systems. Continuous flow gas lift is commonly selected for wells that produce at a very high reservoir pressures which is most applicable to the deep water oil wells. It is a common application in the offshore operations owing to its cost effectiveness, ease of implementation, effectiveness in varying operating conditions and minimal maintenance [1] while intermittent gas lift is normally for wells with relatively low reservoir pressures and rate for effective production. Although high injecting rate can increase production rate in the reservoir, there is a limit to the amount of gas that can be injected into the well as a pressure surge in the entire production equipment could result from high injection rate and low production from too low injection rate, both of which may result in serious operational damage and increase in the operational cost. To this effect there is need to analyze the production under the given well conditions with different gas lift methods to determine the optimum gas lift method and governing factors that affect the selection process. This paper analyzes and compares oil production between continuous and intermittent gas lift systems based on real data obtained from two oil wells in a Niger Delta oilfield and to choose the system best suited to increase the production of the wells.

Many researchers have considered the factors responsible for the selection of the type of artificial lift system to be employed for a given well [2-4]. The operations of types of gas lift systems and their applications was studied [1,5]. Factors affecting gas lift optimization that leads to improved well performance was studied [6-10]. The use of gas lift performance is a common practice to determine the optimum gas lift rate to be allocated to a well in a gas lift analysis involving two wells sharing a common flow line [11]. Computer modelling, simulation and optimization program is required to model, simulate and analyze gas lift optimization for maximum oil production [11-14]. Most field in the Niger Delta are mostly been produced with the continuous lift system due to the high GOR and high reservoir pressure. Not every well in the same field will be compatible with continuous gas lift system, some will be compatible with intermittent gas lift system. The option of simultaneous usage of both the continuous and intermittent lift systems on different wells from the same reservoir for Niger Delta fields has not been really explored, little is also known on how the application of this concept could offer a boost or a decline to the overall production from a reservoir. All of this would be evaluated and confirmed through this paper.

METHODOLOGY

This paper used commercial software in the Integrated Production Modelling (IPM) suite - Production and Systems Performance Analysis (PROSPER) and General Allocation Package (GAP) to model and examine two producing oil wells located in the Niger Delta using nodal analysis. Production data from two wells operating in the Niger Delta were obtained and the behavior of the wells were analyzed and gas lift was implemented at a later stage when the wells were unable to flow naturally. The wells production performances were optimized using continuous and intermittent gas lift systems. PROSPER was used to design the continuous and intermittent gas lift systems for the wells and GAP was used to integrate the whole system for production optimization. This involved an outline description of different methods applied and the procedures undertaken to effectively arrived at the objectives of the study illustrated in Figure 1 and 2.

Nodal Analysis

Nodal analysis was carried out to evaluate the performance of production wells and subsequently evaluate the most viable option for optimizing the wells performance. It involves specifying a nodal point, usually at the bottom hole or wellhead, and dividing the producing system into two parts - the inflow and the outflow. The flow behavior, expressed as flow rate vs. pressure, from the reservoir to the node is called Inflow, and from the node to the outlet, fixed pressure point at the surface is called Outflow.

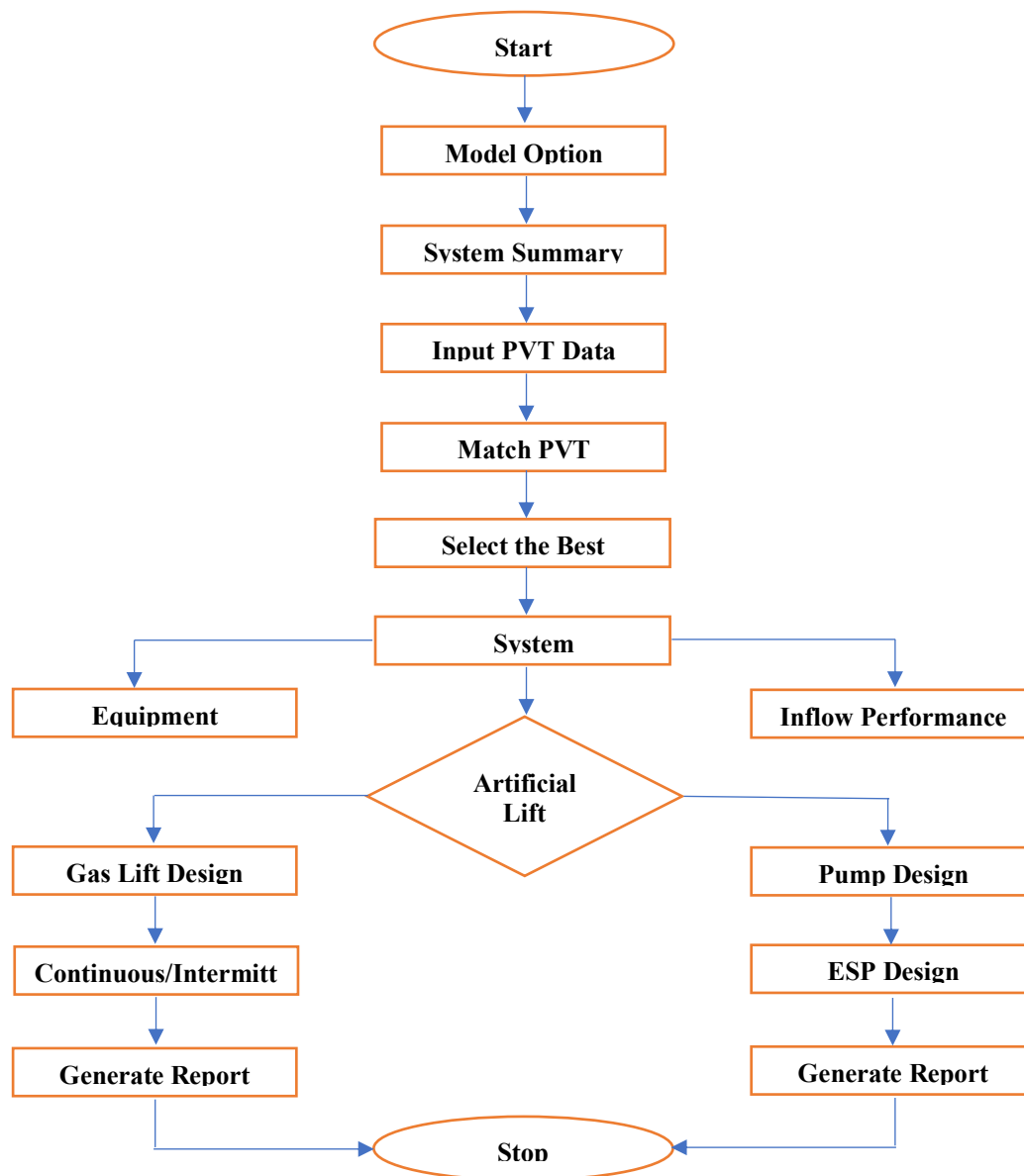


Figure 1: Flow Chart for the Operation of PROSPER Software

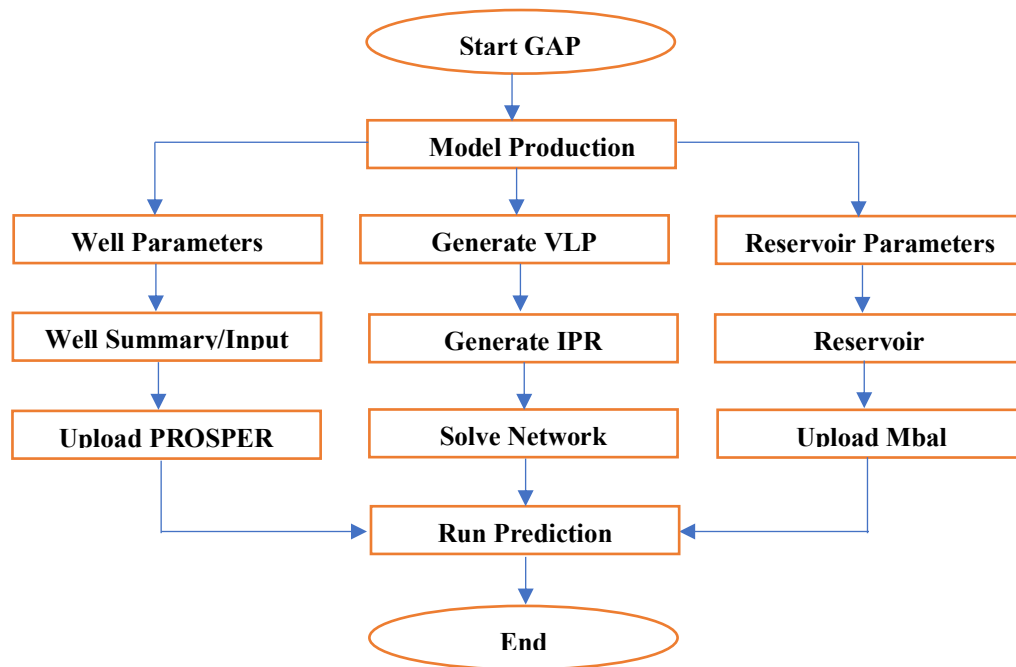


Figure 2: Flow Chart for the Operation of GAP Software

Continuous Gas Lift Design

The screenshot displays the 'GasLift Design - NEW WELL (inter.Out)' window. The 'Design Rate Method' is set to 'Calculated From Max Production'. The 'Valve Type' is 'Casing Sensitive' with a 'Min CHP Decrease Per Valve' of 50 psi. The 'Valve Settings' are 'All Valves PVo = Gas Pressure'. The 'Injection Point' is 'Injection Point is ORIFICE'. The 'Dome Pressure Correction Above 1200psig' is 'No'. The 'Valve Spacing Method' is 'Normal'. The 'Check Rate Conformance With IPR' is 'Yes'. The 'Vertical Lift Correlation' is 'Petroleum Experts 2'. The 'Surface Pipe Correlation' is 'Beggs and Brill'. The 'Use IPR For Unloading' is 'Yes'. The 'Orifice Sizing On' is 'Calculated dP @ Orifice'. The 'Current Valve Type' list on the right includes Valve1, R-20, R-2, R-1D, R-1, Camco, RP-6, RCB, R-20, PK-1, BKT-1, BKT, BK, Baker, and B1. The 'Port Size' and 'R Value' are also visible.

Figure 3 shows the interface when continuous gas lift is selected as the artificial lift method. The input data were almost obtained from the operators of the oil well.

Intermittent Gas Lift Design

Figure 4 shows the interface when intermittent gas lift is selected as the artificial lift method. The required input data were obtained from the operators of the oil well.

INTERMITTENT GAS LIFT - INPUT DATA (inter.Out)			
Input Data			
Surface Injection Pressure			psig
Injection Depth			feet
Gaslift Gas Gravity			sp. gravity
Wellhead Pressure			psig
Valve Port Size			64ths inch
Water Cut			percent
Tubing Liquid Level			feet

Figure 4: Intermittent gas lift design

Sensitivity Analysis

After an initial design has been made, it was important to evaluate how the wells will respond to changing operating conditions in the future. Increasing water production is inevitable for most oil and gas fields with a strong water-drive mechanism, and as a result, it needs to be considered in the wells design. At some point in the producing life of any well, it is possible that the reservoir pressure will be insufficient to lift the fluid to the surface, when the water cut reaches a specific limit because water is denser than oil. As the water cut increases, the hydrostatic/elevation pressure gradient also increases. Using the wellhead pressure, reservoir pressure, and tubing size, sensitivity analysis was conducted to determine the highest possible water cut the well can produce. Also, the effect of gas injection rate and well head pressure on oil production rate were carried out.

RESULTS AND DISCUSSION

Simulation Results of Continuous and Intermittent Gas Lift Wells

The comparison of the cumulative oil production of continuous and intermittent gas lifted system for both wells are shown in Figure 5. The results obtained from the production forecast showed that the continuous gas lift system was suitable for Well 1 as it gave superior oil production when compared to intermittent gas lift system. It was observed that the continuous gas lift Well 1 cumulative oil production was 39.68MMSTB while the intermittent gas lifted Well 1 cumulative oil production was 23.27MMSTB at the end of prediction period of seven years. For Well 2, the results obtained from the production forecast showed that the intermittent gas lift system gave superior oil production when compared to continuous gas lift system performance. It was observed that 30.37MMSTB of cumulative oil production was produced from intermittent gas lifted Well 2 and for the continuous gas lifted Well 2, 21.38MMSTB of cumulative oil production was produced at the end of predicted period of seven years.

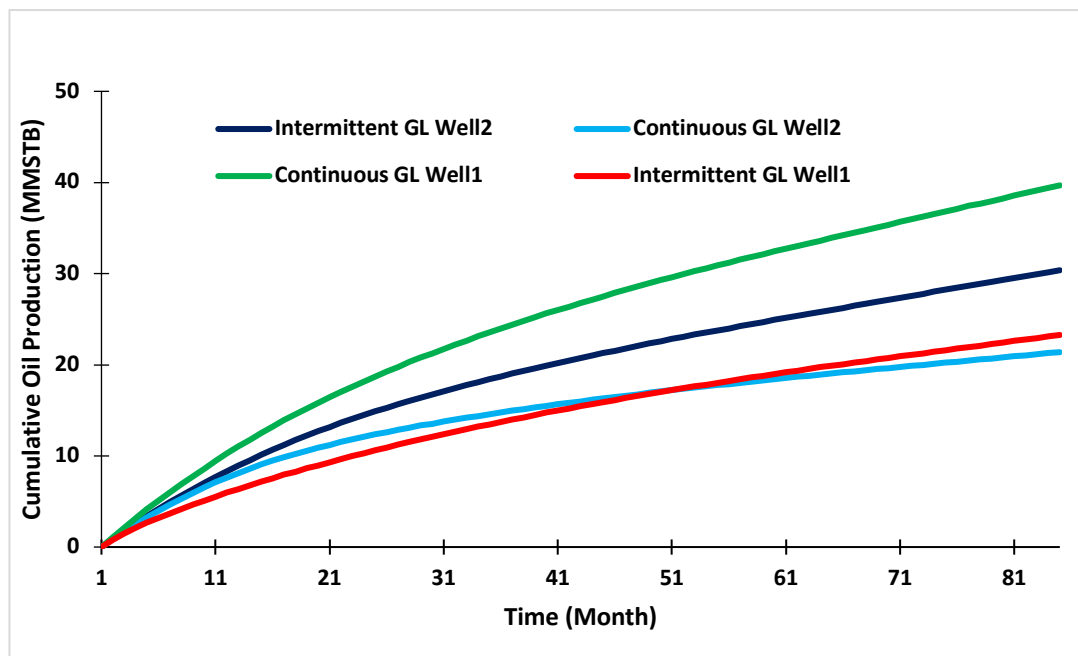


Figure 5: Cumulative comparison of continuous and intermittent gas lifted wells

Results of Sensitivity Analysis

Table 1 presents the sensitivity analysis results of how continuous and intermittent gas lift methods applied on both Wells will respond to changing operating conditions in the future with increasing water cut and decreasing reservoir pressure. For Well 1, it was observed that 901stb/d of oil will be produced when water cut increases to 95% and reservoir pressure increases to 3099psia for continuous gas lift method and 658stb/d of oil will be produced when water cut increases to 95% and reservoir pressure increases to 2902psia for intermittent gas lift method. The results for Well 2 follow similar trend.

Table 1: Sensitivity analysis of water cut on continuous and intermittent gas lifted wells

Operating Point	Well 1				Well 2			
	Continuous		Intermittent		Continuous		Intermittent	
	Oil Rate (STB/D)	Pressure (psia)	Oil Rate (STB/D)	Pressure (psia)	Oil Rate (STB/D)	Pressure (psia)	Oil Rate (STB/D)	Pressure (psia)
WCUT = 0%	1337	2642	919	2415	726	2173	998	1783
WCUT = 20%	1264	2742	863	2526	651	2270	932	1884
WCUT = 40%	1156	2839	810	2628	589	2348	869	1976
WCUT = 60%	1067	2932	756	2727	531	2419	806	2064
WCUT = 80%	978	3022	704	2820	481	2479	751	2140
WCUT = 95%	901	3099	658	2902	437	2530	606	2214

Table 2 shows the sensitivity analysis results of the impact of gas injection rate on continuous and intermittent gas lifted Wells. The optimum gas injection rate that will give optimum oil production was obtained in the sensitivity analysis.

Table 2: Sensitivity analysis of gas injection rate on continuous and intermittent gas lifted wells

Operating Point	Well 1		Well 2					
	Continuous		Intermittent		Continuous		Intermittent	
	Oil Rate (STB/D)	Pressure (psia)	Oil Rate (STB/D)	Pressure (psia)	Oil Rate (STB/D)	Pressure (psia)	Oil Rate (STB/D)	Pressure (psia)
Injection gas = 1mmscf/d	1600	2933	663	3339	651	2270	931	1884
Injection gas = 1.5mmscf/d	1667	2886	734	3267	685	2227	956	1848
Injection gas = 2mmscf/d	1694	2867	761	3239	704	2201	967	1828
Injection gas = 2.5mmscf/d	1701	2862	777	3223	715	2188	974	1820
Injection gas = 3mmscf/d	1700	2863	786	3212	719	2181	974	1820
Injection gas = 3.5mmscf/d	1695	2867	795	3206	719	2181	970	1826
Injection gas = 4mmscf/d	1684	2874	796	3204	716	2185	963	1836
Injection gas = 4.5mmscf/d	1671	2883	795	3205	711	2193	954	1850

For continuous gas lift system in Well 1 the results show that when 1.0MMscf/d of gas was injected, 1598STB/d of oil was produced, when 1.5 (additional 50%) of gas was injected, 1668STB/d of oil was produced (about 70STB/d, representing 4% increment) and when 2.0 (additional 100%) of gas was injected, the 1694 STB/d of oil was produced (about 94STB/d, representing 6% increment). It is observed that the 6% increments in oil production does not worth 100% increment in gas injection or more when compared with the cost of injecting 1MMScF/d to produce 1598 STB/d of oil. This validates the principle of gas injection which states that the greater the amount of gas injected, the lighter will be the fluid column. However, as the amount of gas injected increases, it will also increase the frictional pressure drop. As the injection continues, a stage is reached where any further increase in injection will increase the frictional pressure drop more than it will lighten the fluid column. After this stage, any increase in gas injection will reduce oil production as shown in Figure 6. Hence the optimum gas injection for continuous gas lift system is 1.5 MMSCF/d.

Similarly, for intermittent gas lift system in Well 1 the results show that when 1.0MMscf/d of gas was injected, 663STB/d of oil was produced, when 1.5 (additional 50%) of gas was injected, 734STB/d of oil was produced (about 71STB/d, representing 10% increment) and when 2.0 (additional 100%) of gas was injected, the 761 STB/d of oil was produced (about 98STB/d,

representing 13% increment). It is observed that the 13% increments in oil production does not worth 100% increment in gas injection or more when compared with the cost of injecting 1 MMSCF/d to produce 663STB/d of oil. Hence the optimum gas injection for intermittent gas lift system is 1 MMSCF/d. For continuous gas lift system in Well 2 the results show that the maximum gas that was injected to produce the maximum oil production (719STB/D) was 3.5MMSCF/D. When 2MMscf/d of gas was injected, 704STB/d of oil was produced, when 3.5 (additional 75%) of gas was injected, 719STB/d of oil was produced. The increments in oil production (from 704 to 719STB/D) does not worth the 75% increment in gas injection (from 2 to 3.5MMSCF/D) or more when compared with the cost of injecting 2MMScF/d to produce 704 STB/d of oil. Hence the optimum gas injection for this well under continuous gas lift system is 2 MMSCF/d. Similarly, for intermittent gas lift system in Well 2 the results show that the maximum gas that was injected to produce the maximum oil production (974STB/D) was 2.5MMSCF/D. When 2MMscf/d of gas was injected, 967STB/d of oil was produced and when 2.5MMSCF of gas was injected, 974STB/d of oil was produced. The increments in oil production (from 704 to 719STB/D) does not worth the increment in gas injection (from 2 to 2.5MMSCF/D) or more when compared with the cost of injecting 2MMScF/d to produce 967 STB/d of oil. Hence the optimum gas injection for this well under continuous gas lift system is 2 MMSCF/d. The performance curve for Well 2 is shown in Figure 7.

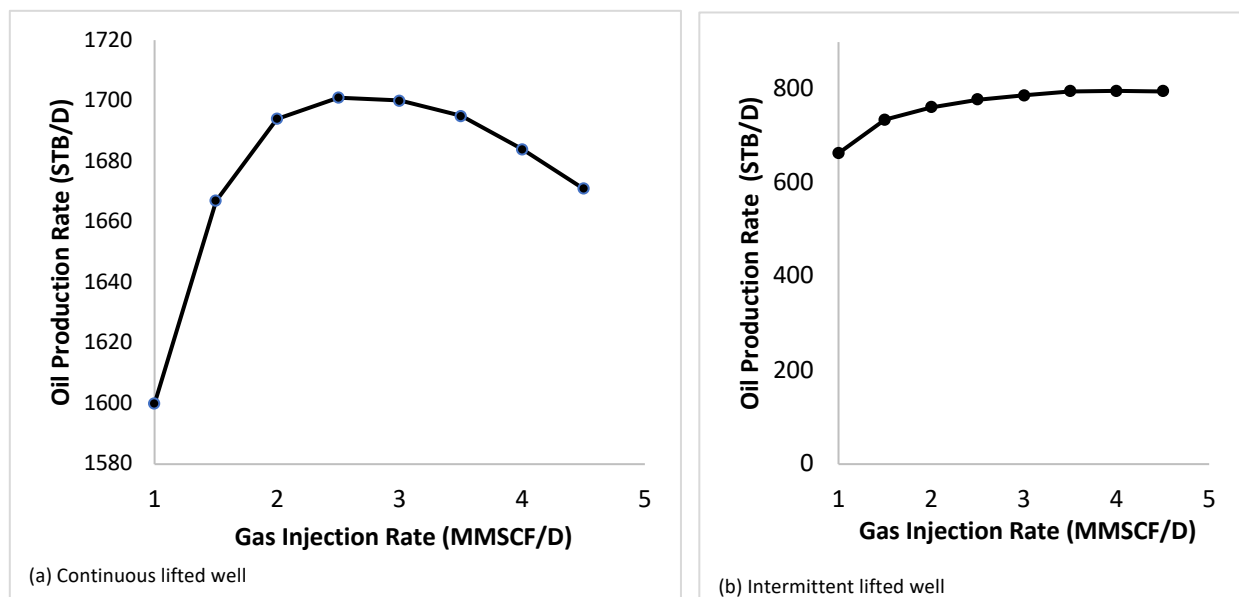


Figure 6: Performance curve of gas lift design for continuous and intermittent gas lift of Well 1

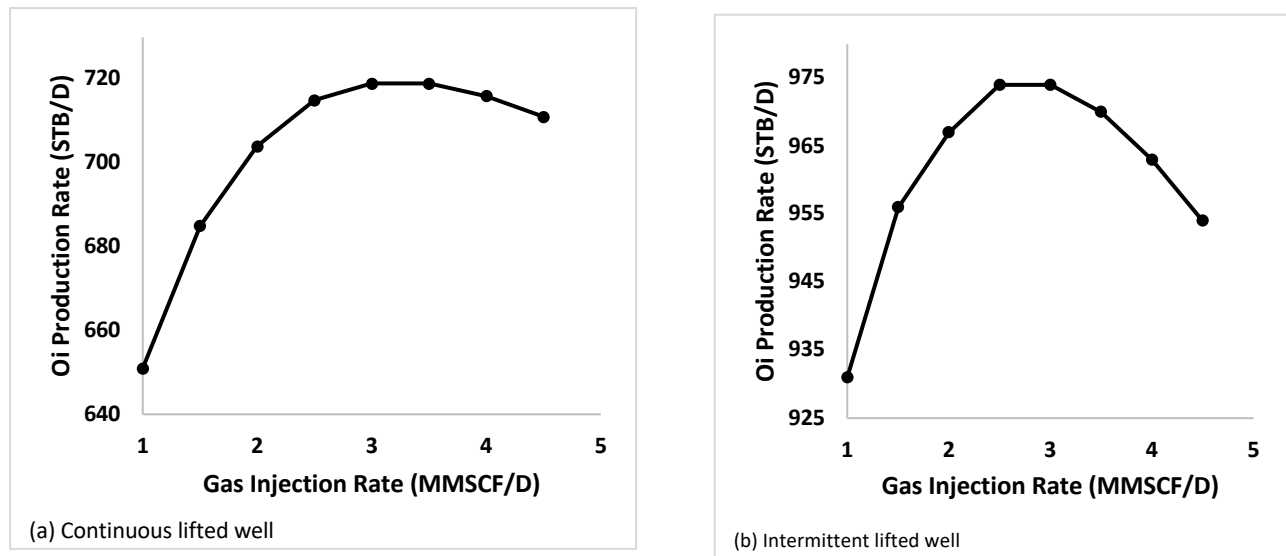


Figure 7: Performance Curve of Gas Lift Design for Continuous and Intermittent Gas Lift of Well 2

Another parameter that affects gas lifted wells is the well head pressure. Table 3 presents the sensitivity analysis of the impact of change in well head pressure on continuous and intermittent gas lift systems on both Wells. The lower the well head pressure, the higher production rate and the higher the well head pressure, the lower the production rate. For continuous gas lift system in Well 1, when the well head pressure is 500psia, 1655stb/d was produced and when the well head pressure was at 1500psia, 819stb/d of oil was produced. Hence, the well head pressure should be kept as low as possible but been mindful of the separator pressure. For intermittent gas lift system in Well 1, when the well head pressure is 500psia, 1116stb/d was produced and when the well head pressure is at 1500psia, 592stb/d of oil was produced. The results for Well 2 follow similar trend.

Table 3: Sensitivity analysis of well head pressure on continuous and intermittent gas lifted wells

Operating Point	Well 1				Well 2			
	Continuous		Intermittent		Continuous		Intermittent	
	Oil Rate (STB/D)	Pressure (psia)	Oil Rate (STB/D)	Pressure (psia)	Oil Rate (STB/D)	Pressure (psia)	Oil Rate (STB/D)	Pressure (psia)
Well head pressure = 500 psia	1655	2260	1116	1981	546	1629	931	1884
Well head pressure = 700 psia	1497	2457	1018	2207	474	1860	792	2084
Well head pressure = 1000 psia	1247	2742	863	2525	362	2175	582	2356
Well head pressure = 1200psia	1074	2925	756	2728	287	2367	448	2517
Well head pressure = 1500psia	819	3181	592	3014	173	235	262	2727

CONCLUSION

Simulation studies were conducted using data from two wells operating in the Niger Delta. The performance of continuous and intermittent gas lifted operation on the two wells was compared. The results indicated that continuous gas lift system will be suitable for a well that has high flow rate and high GOR. Such were the conditions of Well 1 which made the continuous gas lift out performed intermittent gas lift system. For Well 2, the results indicated that intermittent gas lift system will be suitable for a well that has lower reservoir pressure and low productivity and these were the conditions of Well 2 which made the intermittent gas lift system out performed continuous gas lift system. From the results, it can be seen that not every well in the same field will be compatible with continuous gas lift system and not every well will be compatible with intermittent gas lift system. Hence, with effective design of gas lifted wells and sensitivity analysis, the performance of wells can be optimized using either continuous gas lift systems or intermittent gas lift system.

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