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Effective Control of Water Coning Using Downhole Water Sink with Gas Lift Technology

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Abstract: Water coning is the production of water alongside hydrocarbons. It has long been a major problem in the oil and gas industry. It is associated with an increase in the cost of production operations and may reduce the efficiency of the depletion mechanism and recovery of the reserves. Downhole Water Sink (DWS) technology controls water coning in dual-completed wells by concurrently producing water from the bottom completion below the oil-water contact, and oil from another completion at the top of the oil sand. This study aimed to show that DWS combined with gas lift technology has the potential of controlling severe water coning, increasing oil production and improving revenue. This research utilized nodal analysis for several combinations of two tubing strings, one for oil and a second one for water installed in a production casing. A simulation study was conducted on a conventional well, a natural flowing well and a downhole water sink with gas lift well. This was done with the aid of four softwares in petroleum expert (Prosper, Mbal, Reveal and GAP). Using data from 8 wells in the Niger delta, their performances were compared and a detailed economic analysis was carried out. The DWS with gas lift technology gave the best result with an initial oil production rate of 463,805.2 STB/d, and declined to 342,563.5 STB/d of oil production after 10 years (just 26% decline), mere 0.09% water cut and 500% revenue increase. Hence, the DWS with gas lift technology proved to be the best technology for controlling water coning, sustaining high production rate and increasing revenue.

I. INTRODUCTION AND BACKGROUND

Oil-bearing formations are often underlain by bottom water aquifer. An oil well completed in such a formation initially produces water-free hydrocarbons, but as the production continues, water saturation increases around the wellbore and finally bottom water finds its way into the well. The production of oil at a rate higher than the critical rate from these formations results in water production. This production of water is termed as ‘water coning’ and it is associated with an increase in the cost of production operations and may reduce the efficiency of the depletion mechanism and the recovery of the reserves. Until now, countless efforts have been made to understand and control this phenomenon using various methods; perforating far above the original OWC; keeping production rate below the critical value, creating a permeability barrier between the oil and water zones by injecting resins, polymers or gels, using horizontal well to delay the coning speed, controlling the fluids mobility in the reservoir, injecting the produced fluid back to the reservoir, producing oil and water separately by downhole water sink (DWS) wells and so on. However, most of these methods just delay the water coning development and could not totally solve the water coning problem. The critical oil rate is usually too low to be economical for most conventional wells and short penetration could not solve this problem in nature. Permeability barrier just delays the coning development speed and it might depress the water drive; water could bypass barrier and breakthrough to the oil perforation when the oil rate is high. Water cresting is hard to solve in horizontal well as water coning in vertical well. Produced fluid injection back is effective at the beginning of oil production, more and more oil should be injected back to the reservoir with the development of oilfield which makes it impossible to carry out in real practice. The severity of this problem can be seen in the Niger Delta oil reservoirs where we have matured oil fields with bottom water aquifers which have caused abandonment of reservoirs without sufficient recovery of hydrocarbons in place. DWS well is a relatively new method compared to the others. It can control water coning from its source and even completely eliminate it. It is more effective than other methods when the water drive is strong.

Downhole Water Sink (DWS) technology controls water coning in dual-completed wells by concurrently producing water from the bottom completion below the oil-water contact, and oil from another completion at the top of the oil sand. It has been shown that DWS improves well productivity, increases oil recovery, and could produce oil-free water for direct injection or overboard dumping offshore. To date, DWS has been applied in natural flowing wells or wells where a downhole pump can be easily installed [1]. The water coning problem has been studied since 1935. The first of the analytical correlations was that developed by Muskat and Wyckoff in [2], they solved a Laplace equation for single phase flow. Chaney et al in [3] used potentiometric models to determine the critical rates in vertical wells. Chaney pursued the coning critical rate problem both analytically and experimentally. Pirson and Mehta in [4] presented the results of studies performed using numerical simulators. One of the solutions is the re-injection of produced oil into the reservoir below the oil zone perforations to suppress the development of the cone. This technique known as the “Oil

Doublet Model" was not attractive economically. Considering the cost of the dual completion string, Driscoll in [5] suggested a variant of the dual perforation technique. He suggested two perforations – one in the oil zone and one in the water zone below the original oil-water contact. The demerit of this approach is the reduction in oil rate as a result of the increased hydrostatic head of the co-mingled fluid. Ehlig-Economides et al in [6] observed that the concept of critical rate is a misnomer as water is bound to be produced in any reservoir with strong bottom water drive. They also observed that total penetration and dual penetration method of completion yields the most of oil production and recovery but at a cost of handling high rate and volume of water production. Meyer and Garder in [7] showed that their analytical expression consistently predicted a too low critical rate, because they assumed that water break through when the apex of the cone reaches the radius of the well. Schols in [8] showed that water breaks through slightly before the apex reaches the bottom of the well. Abass et al in [9] stated that all previous models yielded great critical rates when the length of the perforated interval is zero, which they justly pointed out to be physically impossible. They proceeded to determine a critical, water-free, production rate under unsteady state conditions. Chaperson in [10] provided a simple and practical estimate of the critical rate under steady state or pseudosteady-state flow conditions for an isotropic formation and proposed two relationships for predicting gas and water coning. Efros in [11] proposed a critical flow rate correlation that is based on the assumption that the critical rate is nearly independent of drainage radius. The correlation does no account for the effect of the vertical permeability. Karcher et al in [12] proposed a correlation that produces a critical oil flow rate value similar to that of Efros` equation. Siddiqui and Wojtanowicz in [13] used a two-dimensional finite difference simulator to determine the behavior of a water cone under various conditions. They used a scaled radial symmetry element model with lateral influx to vary some of the numerical results.

Downhole water sink (DWS) technology was proposed in 1991 [14]. They successfully showed that this novel method actually increases the ultimate oil recovery, prevents water coning and increases oil production rate without water breakthrough. Kurban in [15] built one of the earlier DWS well models using the numerical reservoir simulator ECLIPSE. He addressed the capillary transition zone and relative permeability hysteresis, which were later re-evaluated by Inikori in [16]. Inikori concluded that a capillary transition zone results in a narrower inflow performance window, while hysteresis effects did not create significant differences in the inflow performance window for the same endpoint relative permeabilities. Armenta in [17] analyzed DWS completions for gas wells with bottom water support using numerical reservoir simulation. Effect of impermeable barriers on performance of conventional and DWS wells was studied using a scaled physical model (radial sand pack) and numerical simulator in [18]. The study revealed that in homogeneous reservoirs, DWS would reduce water-cut by draining water from the bottom completion and producing more oil from the top completion. It was also shown that placement of a man-made impermeable barrier around the wellbore would not stop the water cone from forming. DWS well can control water coning from its source and even completely eliminate it. It is more effective than other methods when the water drive is strong. However, it has its own drawbacks. All have successfully shown that DWS technology work in terms of water coning reversal but lack the ability to reduce hydrostatic pressure. Previous studies mostly focused on comparing DWS with conventional completion technique. However, most of these methods just delay the water coning development and could not totally solve the water coning problem.

Methodology

In this study, four existing commercial softwares in Petroleum Expert were used to simulate and study coning problem in bottom water drive reservoir. They are; Integrated Production Modeling (IPM); (Prosper, Mbal, Reveal and GAP). Conventional, and 'DWS and Gas Lifted' wells were modeled for water coning control and their performances were compared. Reveal software was used for the reservoir description while prosper software was used for the Nodal analysis. This study employed nodal analysis for several combinations of two tubing strings; one for oil and the other for water installed in a production casing. First, nodal analysis was conducted separately for the water and oil tubings in order to define their operational ranges. Then, the two solutions were combined to describe the operational domain of the well.

Data Collection

Production history data from eight wells operated in Niger Delta oil field were obtained and the chosen wells were subjected to water coning control using Downhole Water Sink with Artificial Gas Lift Technology. The screening of wells were done based on the following scenarios; Moderately high water cut; Excessively high water cut; Moderately high GOR; Excessively high GOR.

Table 1: Actual Wells Test result from a typical Niger Delta field

Well name	Well status	Date	Duration, hrs	Choke, Inches	WHP (PSI)	SEP (PSI)	RESERVOIR (PSI)	BHFP (PSI)	OIL (STB/D)	Water Cut %	GOR scf/stb	GAS kscf/d	Total Liquid, STB	TGLR, STB/D
Well 1	Flowing	12-Dec-14	24	70/64	450	300	3800	1100	665	60	838	557	1663	152
Well 2	Flowing	16-Jan-15	24	108/64	520	340	3100	1520	830	37	1530	1270	1338	649
Well 3	Flowing	24-Jan-15	24	74/64	430	350	3010	1400	784	30	2337	1832	992	3861
Well 4	Flowing	2-Jan-15	24	1	480	360	3200	1050	2101	19.2	467	985.3	2610	377
Well 5	Flowing	1-Jan-15	24	50/64	560	410	3300	1340	2810	18	222	623	2810	222
Well 6	Flowing	17-Jan-15	24	104/64	440	400	3000	1200	2365	15	222	623	2810	222
Well 7	Flowing	18-Jan-15	24	200/64	430	400	2900	1450	2177	0	553	2204	2177	1012
Well 8	Flowing	3-Jan-15	24	121/64	380	350	3000	850	2029	0	437	887	2029	437

Table 2: collected fluid properties (FP) of the 8 oil wells

FP	Well 1	Well 2	Well 3	Well 4	Well 5	Well 6	Well 7	Well 8
q_l	0.8224	0.5168	0.7486	0.8541	0.9684	0.5876	0.5891	0.2584
q_g	0.7452	0.9866	0.665	0.2253	0.8901	0.0254	0.0478	0.0775
API	40	35	39	45	36	44	37	41
B_o	1.208	1.032	1.035	1.245	1.153	1.18	1.28	1.98
B_g	0.0098	0.0093	0.0293	0.0091	0.005	1.002	0.012	0.009
T	210	645	682	654	618	644	668.5	625
P	4000	2425	2280	1720	2505	2792	3540	4000
μ_o	1.02	0.89	0.92	1.04	1.56	0.88	1.7	2.4
μ_g	0.05	0.08	0.06	0.07	0.03	0.09	0.03	0.07
R_s	838	450	320	268	400	336.63	1052	2520

Results from Nodal analysis

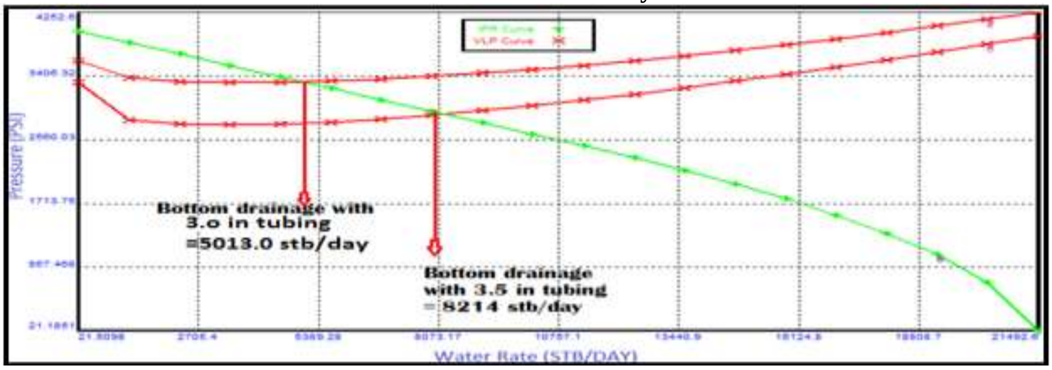


Figure 1: Tubing Selection for DWS Completion

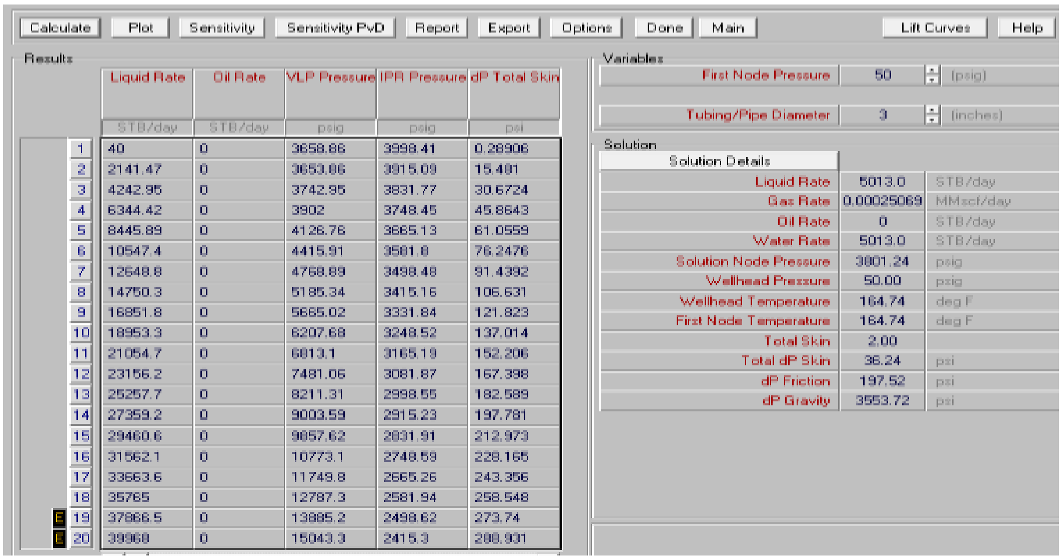


Figure 2: Result of Tubing Selected for DWS Completion

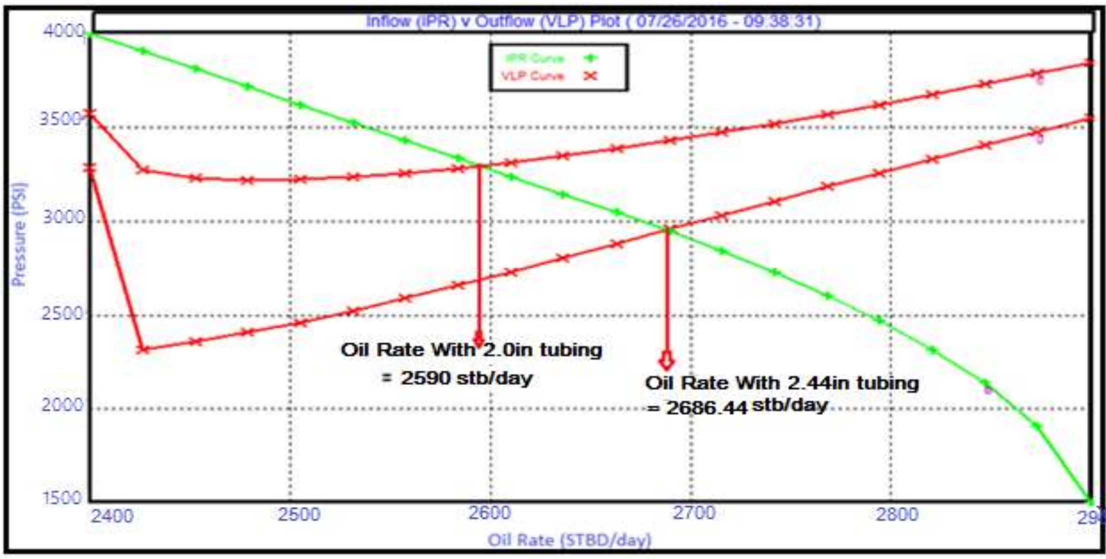
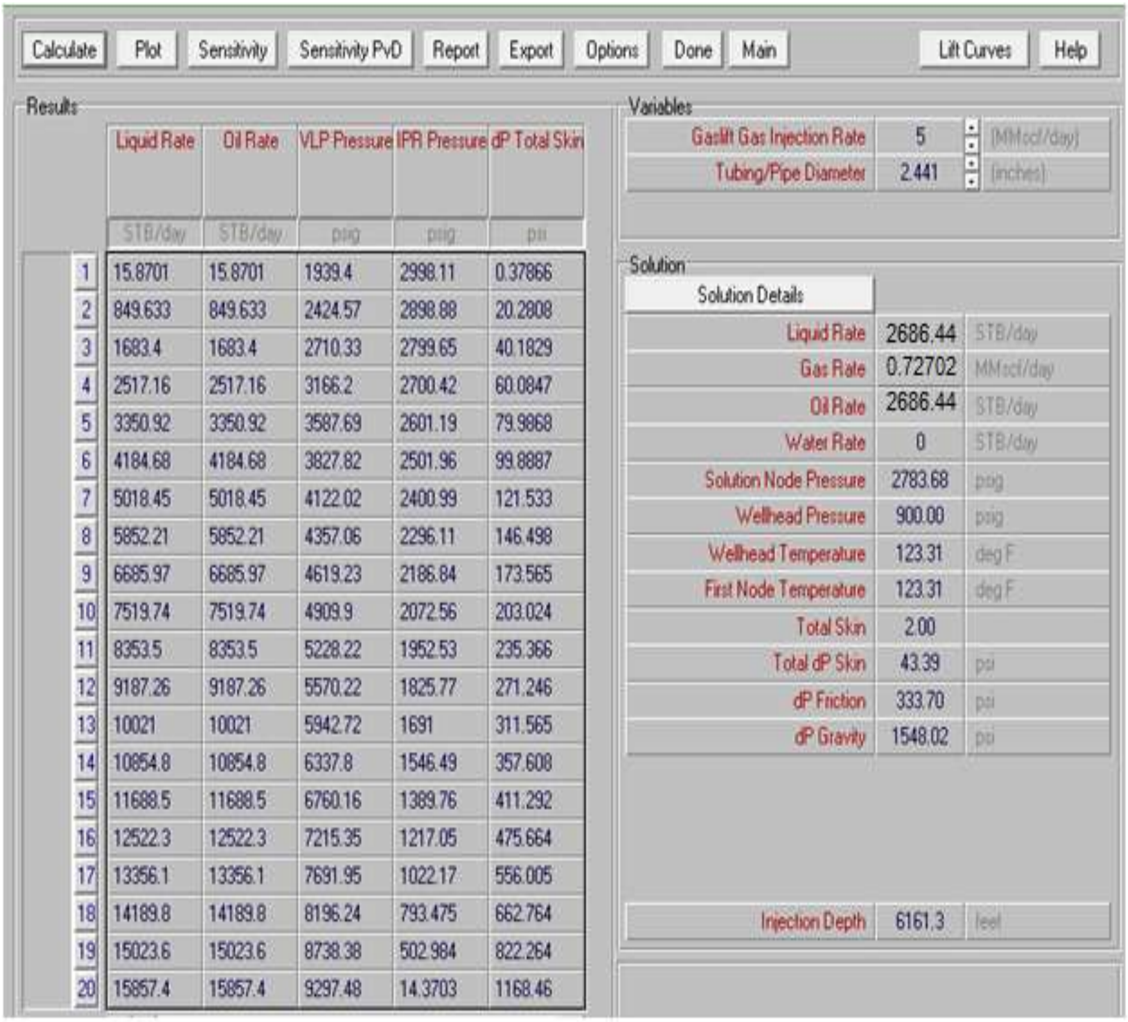


Figure 3: Tubing Selection for Top Completion



	Liquid Rate (STB/day)	Oil Rate (STB/day)	VLP Pressure (psig)	IPR Pressure (psig)	dP Total Skin (psi)
1	15.8701	15.8701	1939.4	2998.11	0.37866
2	849.633	849.633	2424.57	2898.88	20.2808
3	1683.4	1683.4	2710.33	2799.65	40.1829
4	2517.16	2517.16	3166.2	2700.42	60.0847
5	3350.92	3350.92	3587.69	2601.19	79.9868
6	4184.68	4184.68	3827.82	2501.96	99.8887
7	5018.45	5018.45	4122.02	2400.99	121.533
8	5852.21	5852.21	4357.06	2296.11	146.498
9	6685.97	6685.97	4619.23	2186.84	173.565
10	7519.74	7519.74	4909.9	2072.56	203.024
11	8353.5	8353.5	5228.22	1952.53	235.366
12	9187.26	9187.26	5570.22	1825.77	271.246
13	10021	10021	5942.72	1691	311.565
14	10854.8	10854.8	6337.8	1546.49	357.608
15	11688.5	11688.5	6760.16	1389.76	411.292
16	12522.3	12522.3	7215.35	1217.05	475.664
17	13356.1	13356.1	7691.95	1022.17	556.005
18	14189.8	14189.8	8196.24	793.475	662.764
19	15023.6	15023.6	8738.38	502.984	822.264
20	15857.4	15857.4	9297.48	14.3703	1168.46

Figure 4: Result of Tubing Selected for Top Completion

Predicted Simulation results of the conventional well

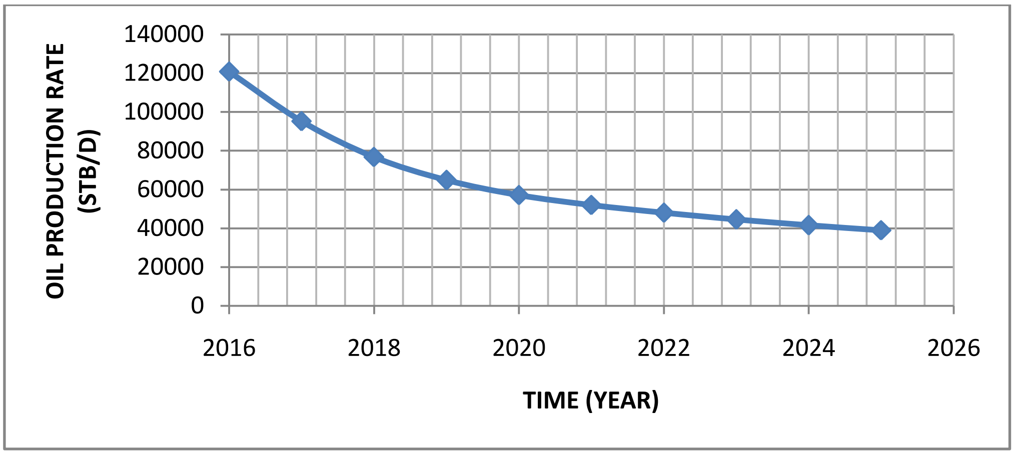


Figure 5: Oil Rate Plot for the conventional well

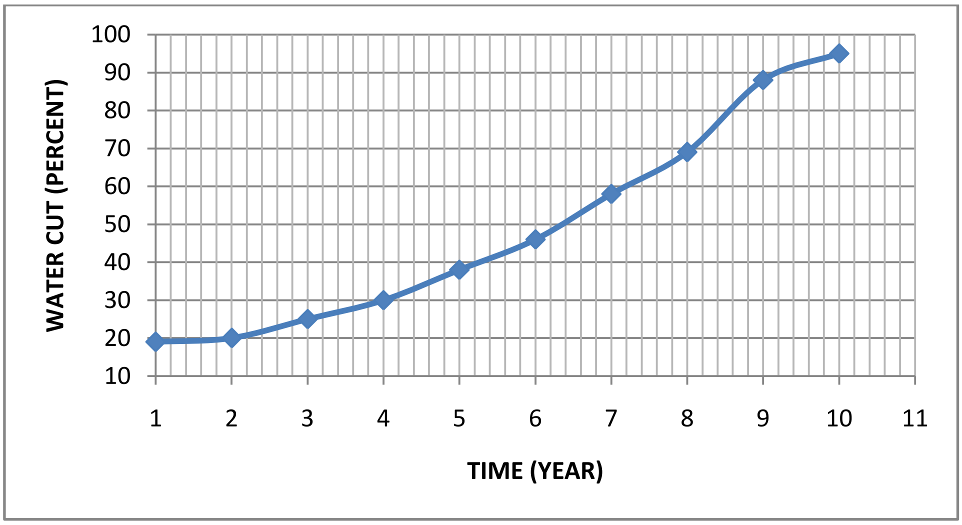


Figure 6: water cut plot for the conventional well

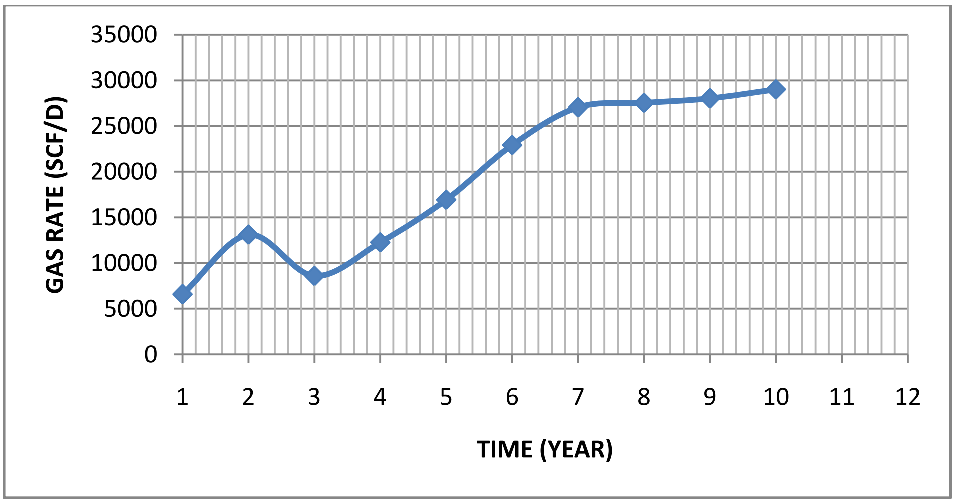


Figure 7: Gas Rate Plot for the conventional well

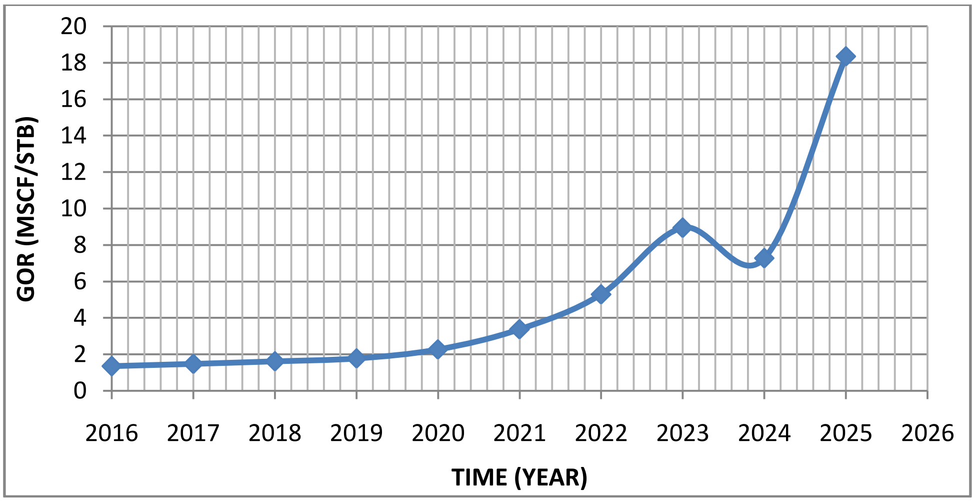


Figure 8: GOR plot for the conventional well

Table 3: Simulation Result From the Conventional well

Date (Year)	Oil (STB/D)	Gas (MSCF/D)	GOR(MSCF/STB)	Water Cut (%)
2016	120,797.2	6.58048	1.342908	19
2017	95,188.6	13.09639	1.481618	20
2018	76,723.9	8.5802	1.615878	25
2019	64,785.5	12.25639	1.775441	30
2020	57,086	16.9152	2.268084	38
2021	51,961.5	22.90987	3.374834	46
2022	47,985.6	27.02743	5.285855	58
2023	44,472.2	27.522	8.941971	69
2024	41,485.3	28.000	7.268308	88
2025	38,943	28.999	18.3569	95

Simulation Results of Natural Well Flow in Dual Completion

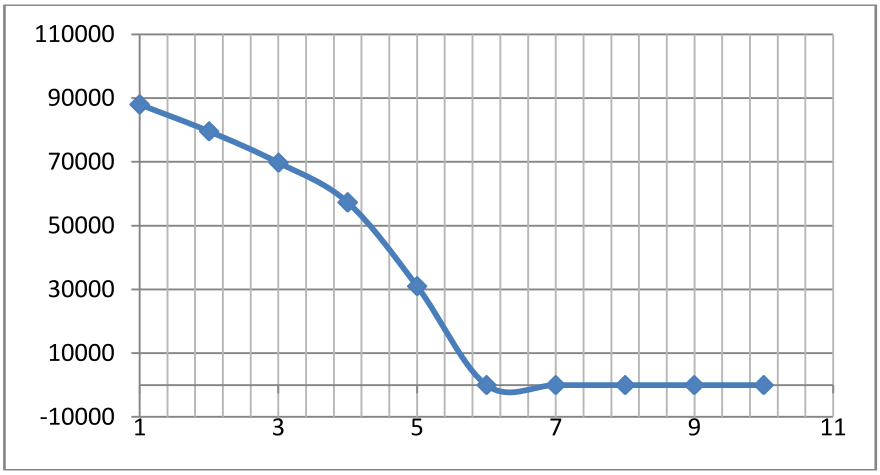


Figure 9: Oil Production in DWS Well with no gas lift

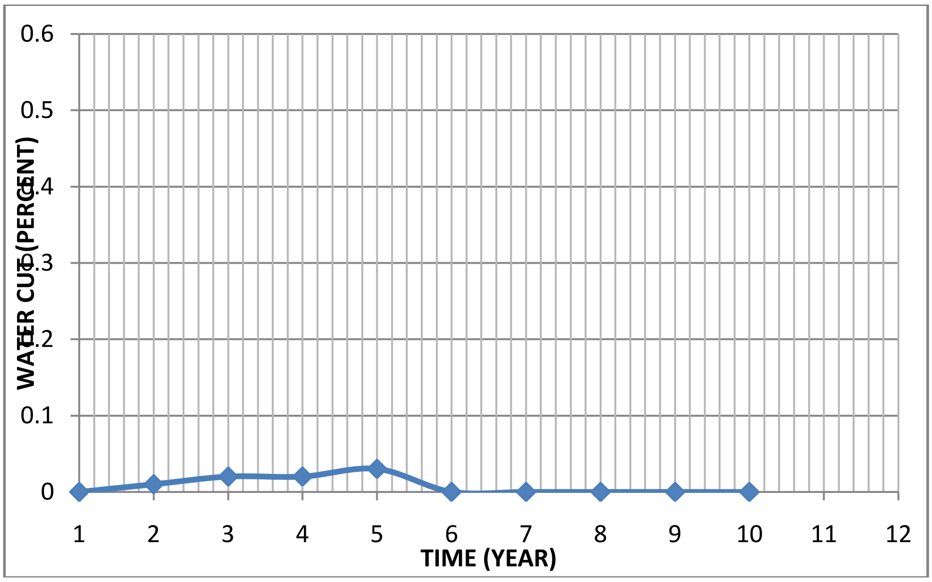


Figure 10: Water Cut at Top Completion

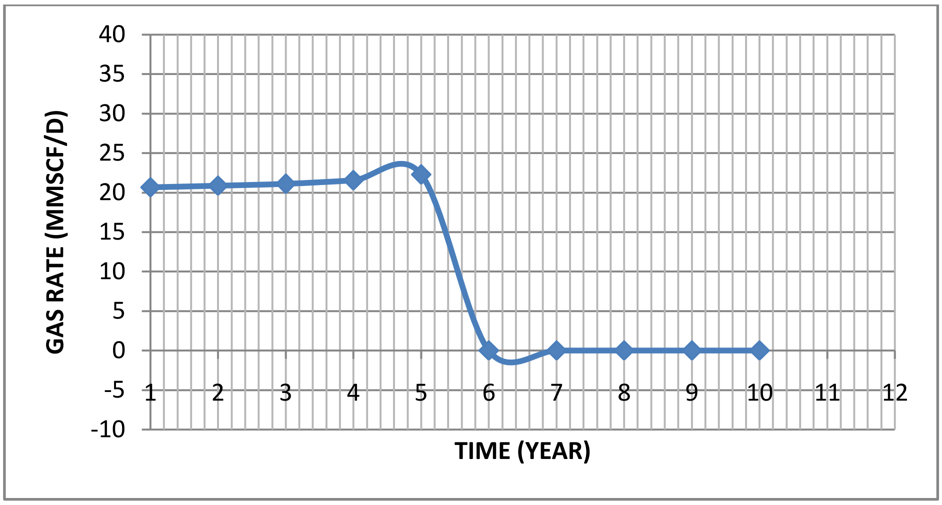


Figure 11: Gas Production Rate at Top Completion

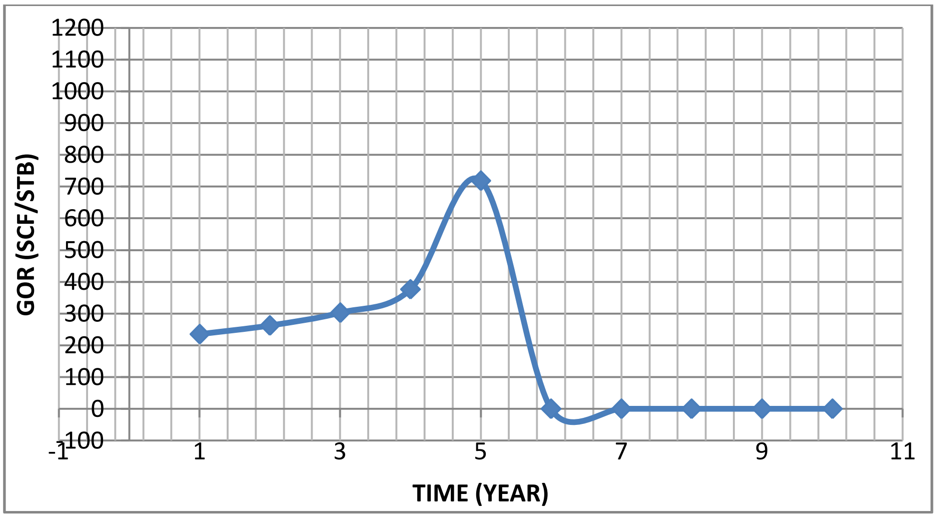


Figure 12: GOR Production Rate at Top Completion

Table 4: Simulation Result From Dually Completed well with no gas Lift

Date (Year)	Oil (STB/D)	Gas(MMSCF/D)	GOR(SCF/STB)	Water Cut (%)
2016	87,929.3	20.659	234.9501	0
2017	79,563.2	20.87	262.3072	0.01
2018	69,741.6	21.092	302.4307	0.02
2019	57,223.2	21.536	376.3509	0.02
2020	30,992.6	22.262	718.3005	0.03
2021	0	0	#DIV/0!	0
2022	0	0	#DIV/0!	0
2023	0	0	#DIV/0!	0
2024	0	0	#DIV/0!	0
2025	0	0	#DIV/0!	0

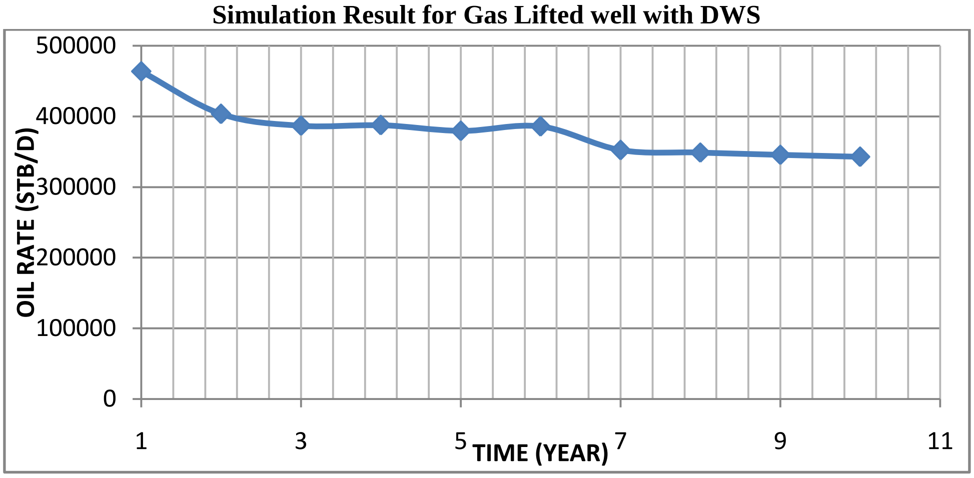


Figure 13: Oil Production with Gas Lift

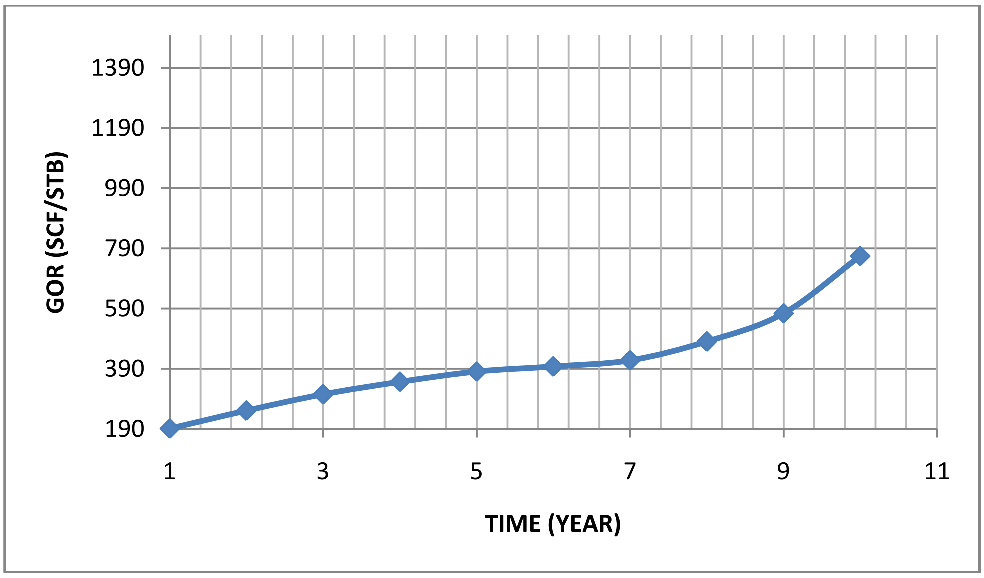


Figure 14: GOR after Gas Lift with DWS

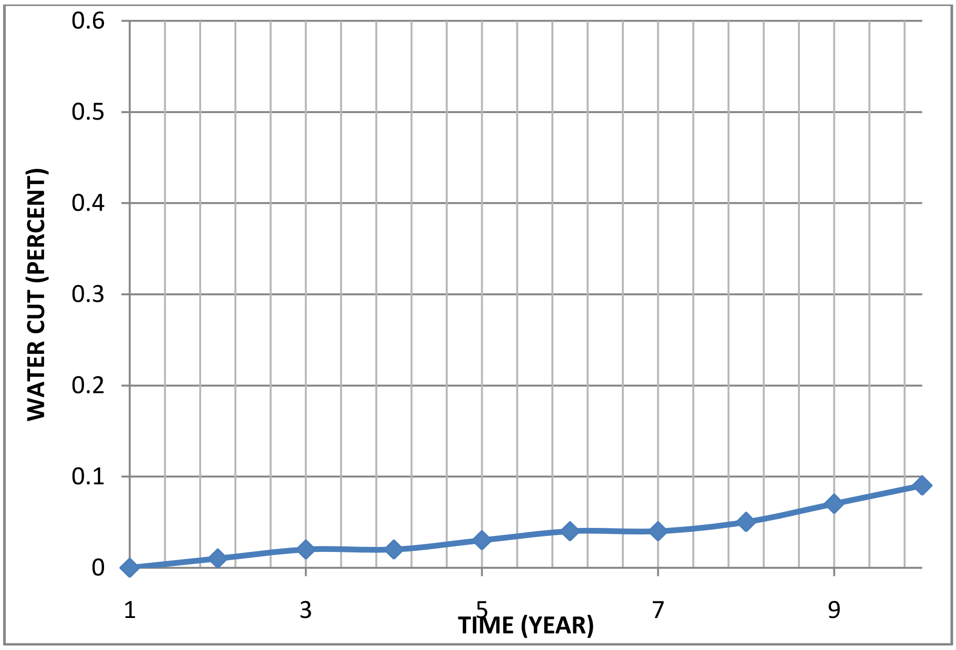


Figure 15: Water Cut at Top Completion after Gas Lift with DWS

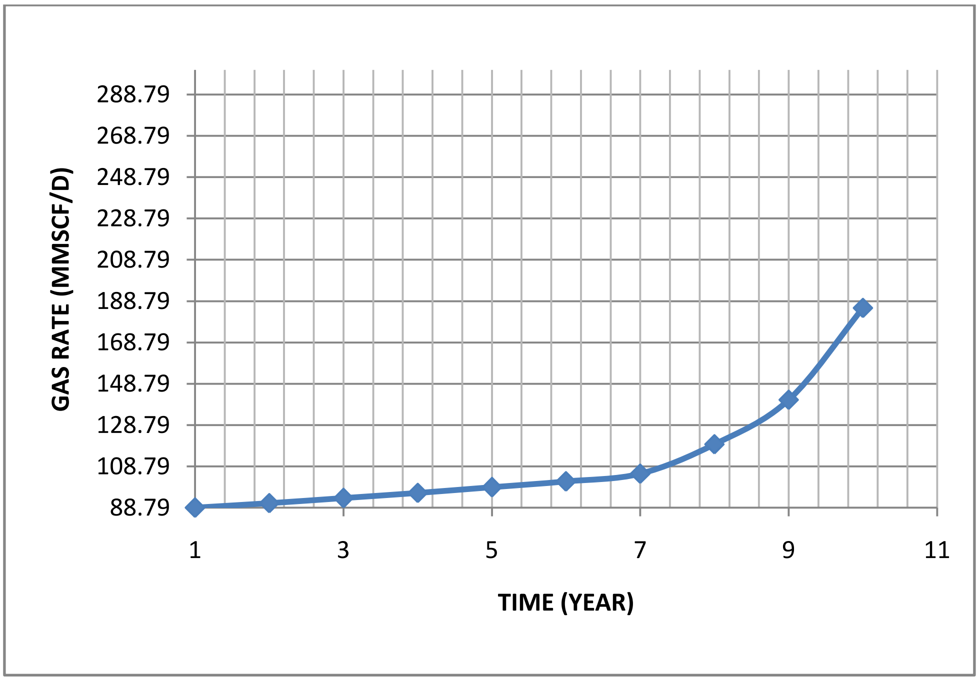


Figure 16: Gas Production Rate after Gas Lift with DWS

Table 5: Efficiency of Continuous Gas Lift in DWS Well

Date (Year)	Oil (STB/D)	Gas (MMSCF/D)	GOR (SCF/STB)	Water Cut (%)
2016	463,805.2	88.79	191.4381	0
2017	403,232.4	91.05	250.666	0.01
2018	386,759.3	93.476	304.721	0.02
2019	387,413.8	96.057	346.2589	0.02
2020	379,257.8	98.719	380.7754	0.03
2021	385,563.7	101.528	397.2708	0.04
2022	352,067	105.351	417.9484	0.04
2023	348,746.6	119.511	480.4528	0.05
2024	345,579.2	141.079	574.4745	0.07
2025	342,563.5	185.562	765.0038	0.09

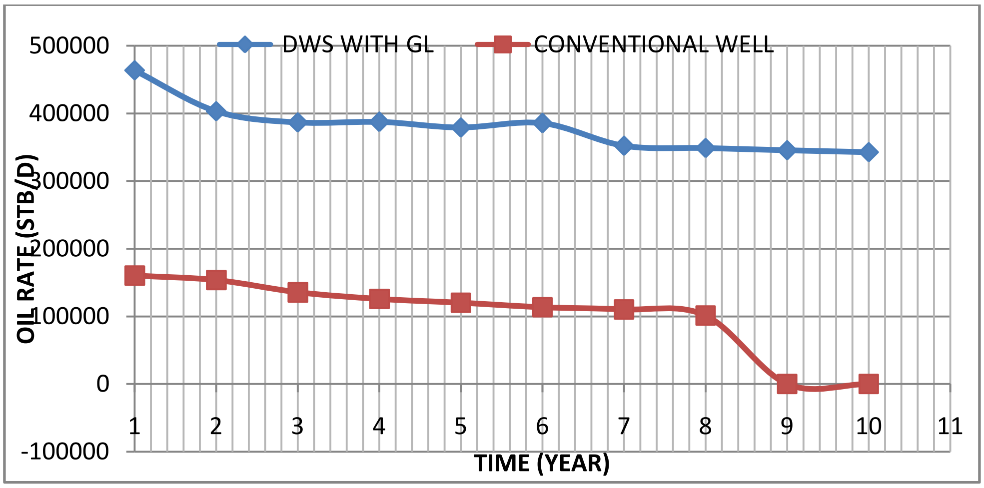


Figure 17*:* Production performance of Conventional, and Gas Lifted well

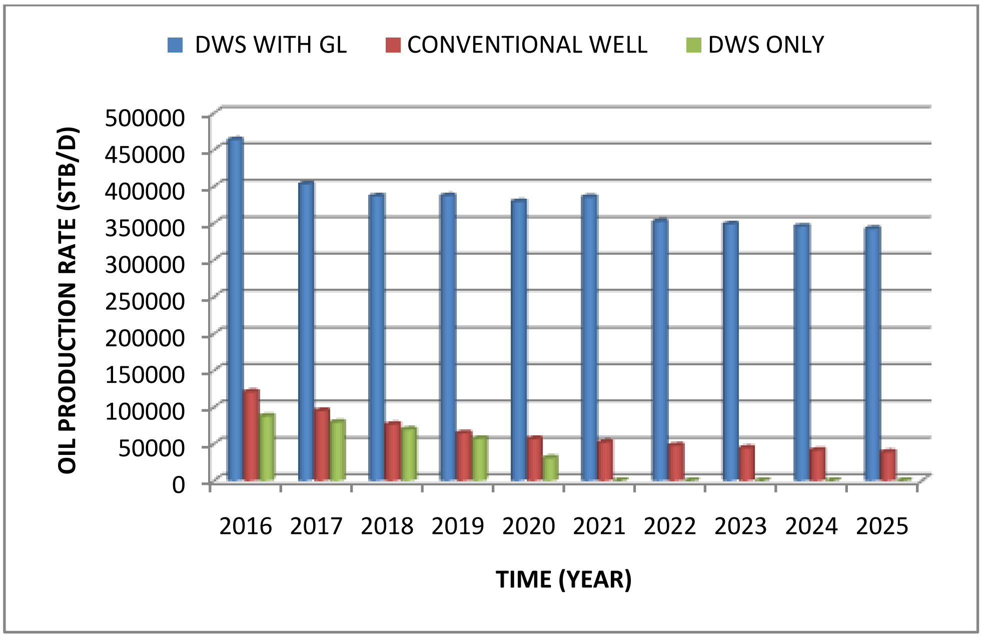


Figure 18: Production performance of Conventional, DWS & Gas Lifted well

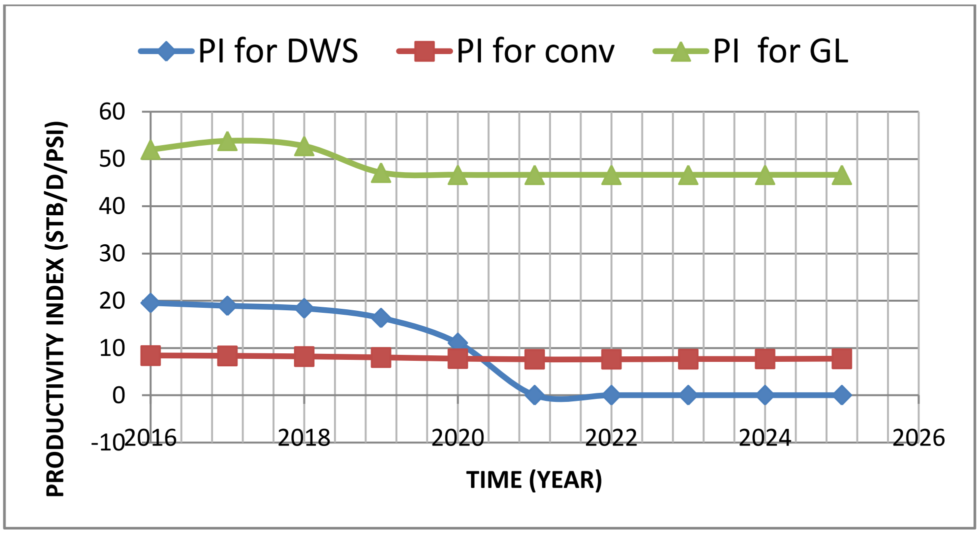


Figure 19: Productivity Index (PI) of Conventional, DWS & Gas Lifted wells

Table 6: comparison of (PI) for Conventional, and 'DWS and Gas Lifted' wells

TIME (YEAR)	PI for DWS	PI for conventional	PI for GL
2016	19.53984444	8.404844587	51.9516
2017	18.94361905	8.34438015	53.81809
2018	18.35305263	8.193443869	52.73566
2019	16.34948571	7.991579825	47.08387
2020	11.03756517	7.78323753	46.62072
2021	0	7.607599181	46.62286
2022	0	7.612001383	46.62494
2023	0	7.657046045	46.62786
2024	0	7.695616767	46.62929
2025	0	7.72865654	46.63122

Economic Analysis

Table 7: Estimated Cost of Conventional, Natural flow & DWS with Gas Lifted well

For Ten Years	DWS with AL Well (STB/D)	Conventional well (STB/D)	Natural flow in DWS Well (STB/D)
Item	Cost ($)	Cost ($)	Cost ($)
Installation/Completion	200,000	0	100,000
Equipment	250,000	0	50,000
Running cost	300,000	200,000	150,000
Maintenance	250,000	100,000	110,000
Water Treatment	100,000	300,000	100,000
Sum	**1,100,000**	**600,000**	**510,000**

Assuming $30 per barrel of crude oil, then the estimated cost for ten years is tabulated as shown Table 8.

Table 8: Estimates of Oil Revenue

Items	DWS with AL Well (STB/D)	Conventional well (STB/D)	Natural flow in DWS Well (STB/D)
Oil rate (bbl/yrs)	3,794,989	639,428.80	325,449.90
Revenue ($/yrs)	113849670	19182864	9763497
Installation/operating	1,100,000	600000	510000
Gross Profit ($)	**112,749,670**	**18,582,864**	**9,253,497**

II. RESULT DISCUSSION

Figures 1 and 2 showed the nodal analysis results of the 0.0762 m (3") and 0.0889 m (3.5") water strings operated in the DWS well with continuous gas lift. The plots represent maximum rates of lifting water in this well for the two strings. More than 8214 STB/day can be lifted with a 0.0889 m (3 1/2") string, as compared to 5013.8 STB/day for the 0.0762 m (3") string, for the same (5MMcf) gas injection rate. Although the 3.5" tubing produces water more than 3" tubing, to extend the well life and maintain the aquifer energy, the 3" string tubing size gives the optimum water production from the lower zone at the rate of 5013.8 STB/Day. Figures 3 and 4 showed the nodal analysis results of the 0.06198 m (2.44") and 0.0508 m (2") for oil strings operated in the same well with continuous gas lift. The plots described the maximum rates of oil produced in this well for the two strings of tubing. The intercept of the two plots represents the maximum oil production rate. More than 2686.44 STB/d can be lifted with a 2.44" string, as compared to 2590 STB/d for the 2" string for the same 5MMcf gas injection rate. Here, the 2.44" string gives the optimum production of oil from the top completion at the rate of 2686.44 STB/day.

Figures 5 through 8 present the results obtained from the conventional well in terms of gas-oil ratio (GOR), gas production rate (GPR), oil production rate (OPR) and water production rate (WPR) versus time. From figure 5, a gradual decline in oil rate was observed throughout the period of production with a corresponding increase in water production rate. After 10 years of production, the oil rate declined from 120,797.2 STB/D to 38,943 STB/D. Water breakthrough occurred after two years and increased to 95% at the end of ten years of production (Figure 6). This is due to the high pressure from the aquifer which pushes the water up to the oil zone. Consequently, the water cut increases rapidly which in turn leads to a reduction in oil production rate. There was also increase in GPR (Figure 7) which also led to an increase in GOR (Figure 8). For the dual completed natural flowing well, the simulation showed the results of the well affected by water coning. Here, the well was dually completed with two tubing strings each; one is producing water while the other is producing oil naturally without any artificial lift. The results obtained in terms of their respective oil production rate (OPR), gas-oil ratio (GOR) gas production rate (GPR) and water production rate (WPR) are presented in Figures 9 through 12. Figure 9 showed the result of the oil production rate (OPR) obtained from the simulation.

It was observed that production started with 87,929.3 STB/D of oil but declined rapidly to 30,992.6STB/D of oil after five years of production. An interesting observation was that the decline trend in oil production changed rapidly with time due to lack of sufficient energy from the oil zone to drive the fluids to the surface. As a result of this, the well only flowed for a period of six years with the help of small gas cap (Figure 11) before it stopped flowing. At this stage, water cut was reduced to about 0.05 percent (Figure 10).

For the dual completion using a combine system of gas lift with downhole water sink technology, the simulation showed the well affected by water coning. The results obtained in terms of their respective oil production rate (OPR), gas-oil ratio (GOR) and water production rate (WPR) are presented in Figures 13 through 16. Figure 13 shows the result of the oil production rate (OPR) obtained from the simulation. It was observed that oil production started with 463,805.2 STB/d and continued with a slight decline to 342,563.5 STB/day after ten years of production. The GOR (Figure 14) increased at the end of ten years due to increase in gas production (Figure 16). And water cut was reduced to about 0.09 percent (Figure 15).

In summary, the results obtained from the production forecast showed that the DWS with gas lifted well gave a superior production rate when compared to natural flow in dually completed and conventional wells. From the results it was observed that the conventional well oil production rate dropped to zero after eight years with water cut increasing to about 95%. This rapid decline in production rate for the conventional well was also noticed in the dual completed well without gas lift. This decline which eventually led to a corresponding decrease in oil production rate was as a result of producing the water (which was the primary source of energy) from different tubing which consequently increased the hydrostatic pressure that led to a corresponding increase in bottomhole pressure and eventually load up the well till it died. But at the injection of gas into the oil production tubing through the operating valve, the hydrostatic pressure was eliminated and the well was back on production with zero water cut.

III. CONCLUSION

Simulation studies were conducted using data from actual wells in the Niger Delta. The performance of conventional wells, natural flowing wells and 'DWS with gas lifted' well had been compared. The results showed that gas lifted wells have higher oil production rate and lower water cut than conventional wells and the natural flowing wells. This study also reflects the economics of controlling water coning using gas lift with DWS as it is relatively cheaper due to the fact that it about maximum oil recovery. DWS with GL wells are the best both in terms of production increase and gross profit which are the major factors in any investment decision making. Hence, the DWS with gas lift technology is capable of improving recovery of oil even in old wells with water coning history.

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