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Production Optimization Using Continuous Gas Lift System

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Abstract:- Continuous gas lift system is a common artificial lift method employed by many oil companies to start up a well or to increase the production rate of the well. The concept aims at lowering the hydrostatic pressure inside the tubing through injection of lighter fluids into the annulus. This work makes emphasis on two producing wells in Agbam-Egbema namely Well A03 and Well A04, with an initial production rate of 6315.88stb/day and 7497.59std/day respectively, overtime production reduced with increasing water cut of 60% in well A03 and also in well A04 having 50% increase in water cut. The drop-in production brought about the implementation of the continuous gas lift system, which is aimed at maximizing production at an optimum economic gas rate. Furthermore, still on maximizing production, the valve port sizes where adjusted to observe the effect it has on the production. For the course of this work, prosper simulation software is used for matching data, model creation, designing the gas lift system and the adjustment of valve-type port size. After implementing the continuous gas lift system, the result gave an optimum production rate of 2666.6stb/day at a gas injection rate of 13MMscf/day with unloading depth 3526.13ft and operating valve depth 8389.29ft for well A03 at 60% water cut and the optimum production rate of 2756.55stb/day for well A04 at an injection rate of 7MMscf/day at 50% water cut at an unloading depth 3530.41ft and operating valve depth 6929.45ft. With the two wells running under the valve-type Camco R-20 normal or Valve type RP-60 Camco Normal.

Keywords:- *Artificial, Continuous Gas Lift System, Hydrostatic, Prosper, Water Cut.*

I. INTRODUCTION

Geological formations that are composed of sedimentary rocks are most likely to possess hydrocarbon fluids within the pore spaces found in the formation, which makes this formation very attractive to engineers and the oil company at large. The discovery of hydrocarbons (oil and gas) brings about geological and engineering processes which aims at extracting the fluid to the surface.

The fluids have energy stored in them which resulted from the pressure in the overlying layers of the earth and heat from the core of the earth. This energy is found within the reservoir at high pressure and temperature. The fluid travels freely to the surface using the natural reservoir energy which acts as the driving force. Continuous production of hydrocarbon in the life of the reservoir will decrease reservoir pressure, water cut increases and productivity will be reduced. For economic reasons, it is advisable to analyse how long a well will produce naturally since pressure gradually drops as production occurs, making recovery process intricate, thus giving engineers the mind-set in making provision for special recovery techniques in other to increase the rate of petroleum recovery.

There are several types of recoverable methods used in the world but the secondary recovery technique which involves artificial lift systems is the most used recovery technique today, and varies differently in methods. The gas lift method is used in this work to maximise production and optimise gas injection. Most importantly the steps and procedures taken in the recovery process are vital in determining the present and future economic value of the producing well.

II. REVIEW OF THE GAS LIFT DEVELOPMENT

Gas lift development first began in Germany in the year 1797, where the act of lifting fluid was experimented in a laboratory by the application of compress gas. While in 1846, compress air was practically used to lift oil from wells in Pennsylvania by an American Engineer, this method of injecting compress air through the annulus for the purpose of lifting continued for years under severe scrutiny before its patent was approved in 1883 making gas lift an acceptable lifting method. Also flow valves of different categories were patented in the year 1929 – 1945 and retrievable valves introduced in 1957, all for the purpose of optimum production. Gas lift system was basically used in the early days to bring back dead wells into production having compress air as its working fluid.

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In today's world more than 90% of the producing oil wells enhance oil production using artificial lift systems, since reservoir pressure drops subsequently as the well is put into production. The gas lift system has been made more safe, economical and operationally more convenient over the years, for instance the working fluids which use to be compress air is being replaced with compress gas which can be manually or automatically injected into the well, but more preferably for modern gas lift applications settle with the automated gas injection. Also, the flow valves and other equipment have been enhanced to meet with safety, high pressure and high-performance requirements. (Petroleum Technology Company, 2008)

Due to the problems encountered in using air as a medium of lifting fluid to the surface such as air mixing with hydrocarbon to form explosive mixture and also causing corrosion being that oxygen is present the need for a safe lifting medium was subsume, which brought about the general acceptance of compressed natural gas to be used for oil lifting.

Earlier, Gas lift adopted the application of the simple 'U'-tube pin-hole principle for oil production in shallow wells, until the introduction of gas lift valve which took gas lift system into deeper wells. (Mitra, 2012).

III. CONCEPT OF GAS LIFT

First, gas is made available which serves as injection fluid from an installed surface compression plant. The use of casing pipe which is drilled into an oil deposit depth of about 15,000 feet, and surrounded by this case pipe is a tubing pipe thus creating a pace called the annulus. Mainly lift gas is introduced to a non-producing or low producing well, meaning the gas lift ratio is low or the fluid gradient is high, whereby reservoir pressure is insufficient to lift fluids to the surface and this method assumes a steady supply of lift gas. Through the annulus pressurized gas is pumped into the tubing, aerating the fluid and reducing hydrostatic pressure in the production string thus creating a difference in pressure between the reservoir and the wellbore. The presence of a pressure differential permits formation fluids to flow to the wellbore and up to the surface. For the purpose of economic benefits and waste reduction the gas is recovered from the oil produced. Over years' production optimization has being a major practice for engineers and the sole aim of gas lift is to make sure fluids in a given reservoir is taken to the surface, precisely a satisfactory portion of the fluid, while maintaining a high-pressure differential between the reservoir and the bottom hole. Oil rate production increases as the bottom hole pressure reduces due to the injected gas which reduces the density of the fluid column, permitting a higher amount of fluid through the tubing. Also, if the injected gas is in excess the bottom hole pressure increases which will reduce production. which means it is important to take note of a well's geometry since too much or too little injection of gas into the well causes surging and slugging where gas phase moves faster than the liquid phase, producing more gas and lesser amount of liquid which brings about production inefficiency. Therefore, the amount of gas injected to maximize oil production should not exceed its optimal gas lift injection rate (GLIR). The gas lift is a robust, easy to install and highly economically method and on this basis give reasons to why it is commonly used in the oil and gas industry. (Kashif , et al., 2012).

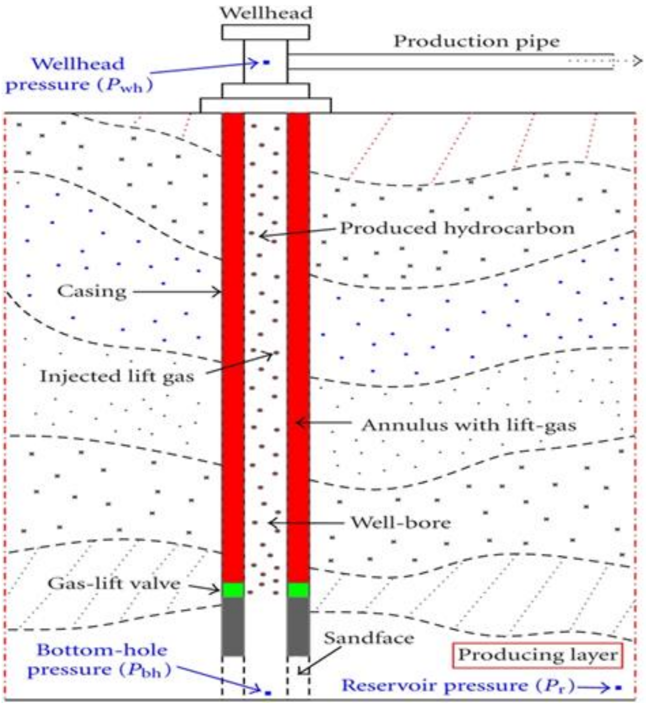


Fig 1 Schematic of a Typical Gas lift System (Kashif, et al., 2012)

Every other methods of artificial lift system acquire a downhole pump installed within the well-space except the gas lift which does not require a pump rod, but operates using high pressure gas which further creates production instability as variation rises in gas injection rate and depth of injection.

The diagram below shows how to determine the point of gas injection to unload a well and the fluid gradient profile. (Mehdi Abbaszadeh Shahri, 2011)

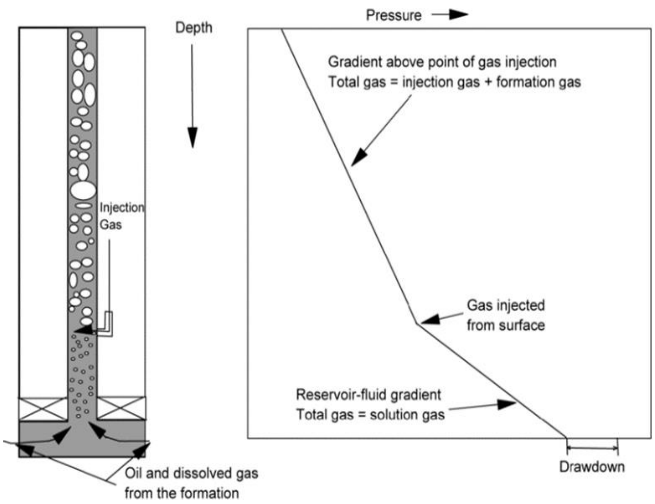


Fig 2 Gas Lift Valve Depth Settings (Petrowiki, 2015)

IV. RESEARCH METHODOLOGY

The prosper program by default is being set to automatically pick the optimum port size for each depth that will yield optimum production, which limits the user from practically observing what happens when a port size is manually selected by the user, which is not the optimum port for that particular depth, and by default the optimum port size for each depth is selected by the program from the ranges of port sizes given for that particular valve. Also, in course of this work, the gas lift valve performance is not authorised in the Prosper program which also limits this work to sight better and more technical observations concerning the effect of valve port size on production. Although, observations were made based on manufacturer valve types found in the prosper program database.

A. Continuous Gas Lift Optimization Methods in Gas Lift Well

Continuous gas lift system is applied to achieve the work goal of this thesis. Yes! This particular artificial gas lift system is very common and has proven very effective in production optimization over the years.

For our case study below the continuous gas lift system will be used to optimize production with the help of the Prosper program which plays an important role in the optimization process, some of the important roles include matching best-fit parameters automatically, well modelling, design of the gas lift system, adjustment of valve types which will automatically adjust the port size (prosper default) also the calculations of different sensitivity plot which gives an accurate idea of the well's performance provided the required data are properly inputted.

- *Case Study*

Base on the case study which is sighted in the southern part of Nigeria, precisely the Abam-Egbema field having two producing wells A03 and A04, producing initially at 6315.88stb/day and 7497.59stb/day respectively. Overtime, as production continues the rate of oil production dropped to 1237.78stb/day at 60% water cut in well A03 and also for the case of well A04, production dropped to 1404.08stb/day at 50% water cut. This drop-in production for both wells initiated the use of a continuous gas lift system, which aims at improving production rate at an optimum injected gas rate which in return should yield financial growth. Also, this work goes further to see the effect of oil production when valve port size is changed. (From the Prosper recommended Valve type database)

B. Prosper Start-Up

The Prosper software progresses from left to right and there is also a workflow system guide to which a good simulation and optimization process can be achieve. The workflow system analysis in Figure 3 provides the stages for easy and accurate imputation of data as to start using the Prosper program.

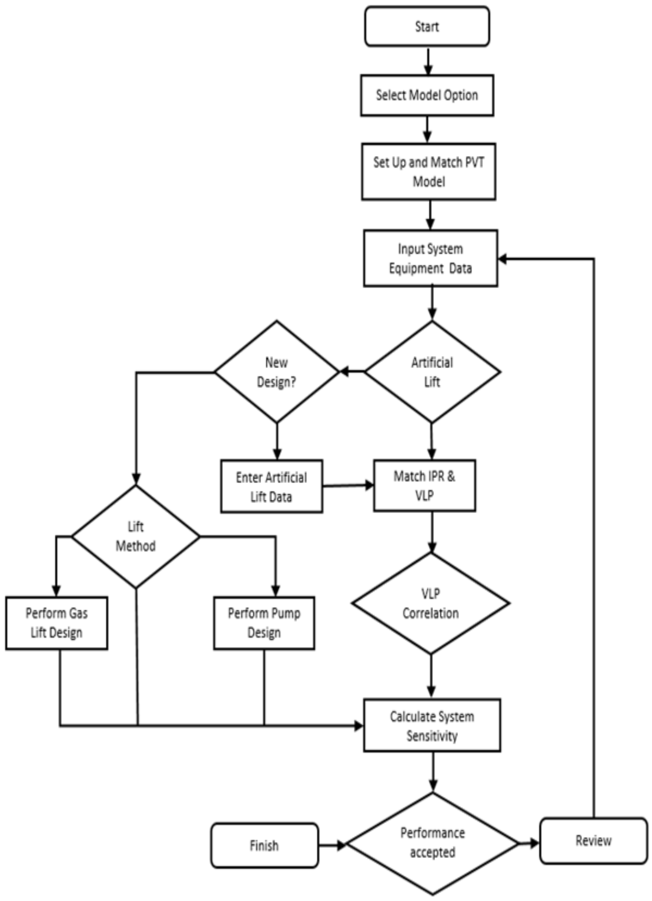


Fig 3 Prosper Workflow System Analysis (Okoro & Ossia, 2015)

- *Building a Case Study of Well A03*

The Prosper program will permit users to input data starting from the left hand side, precisely by opening the 'option summary bar' where the kind of fluid to be used is selected which is 'oil and water', 'black oil' as the method and the artificial method selected is 'none' these options were selected in other to create base case model which will be tune to the field data.

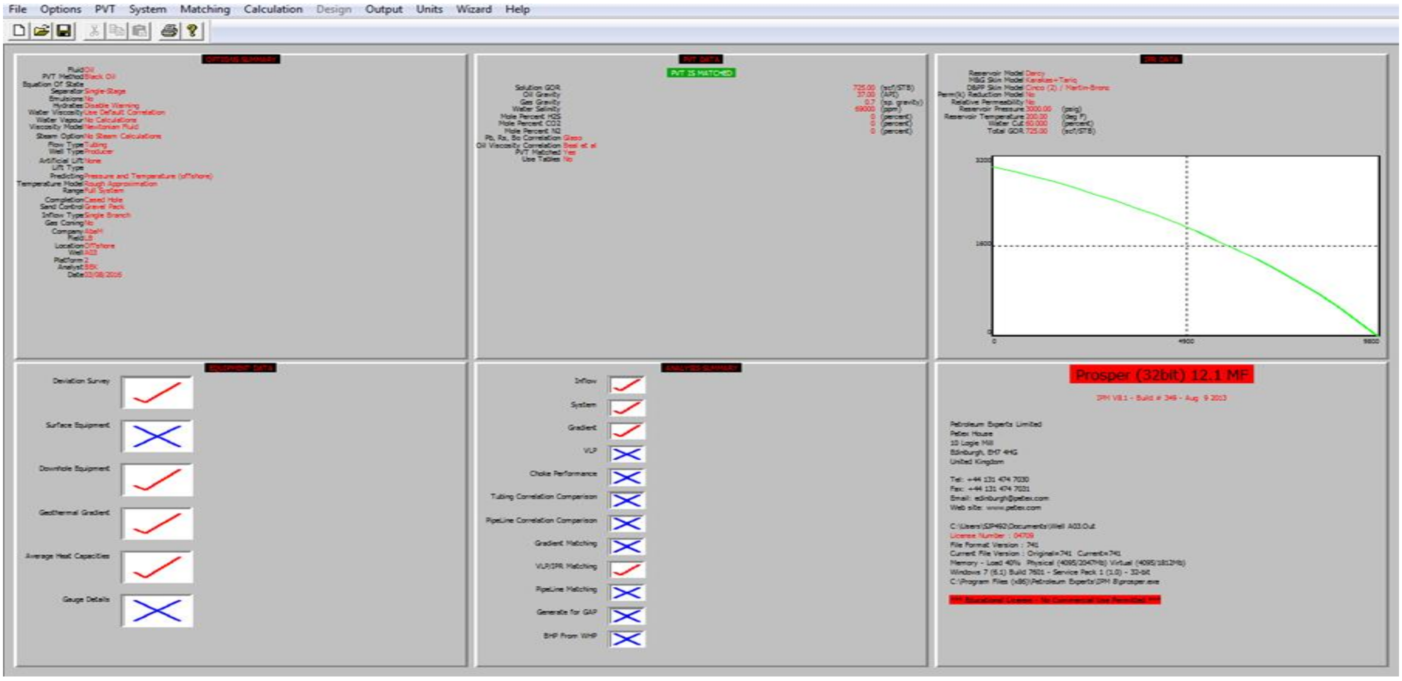


Fig 4 A Typical Prosper Interface

➢ *Quality Check of PVT Data*

The PVT data helps to predict fluid properties accurately as pressure and temperature tends to fluctuate within the reservoir. The black oil model data for PVT has being inputted into the Prosper program as seen in and the method used was a single stage flash of recombined reservoir fluid. A nonlinear regression is used for this correlation (parameter 1 & 2) and a standard deviation is displayed showing the closeness of the fit.

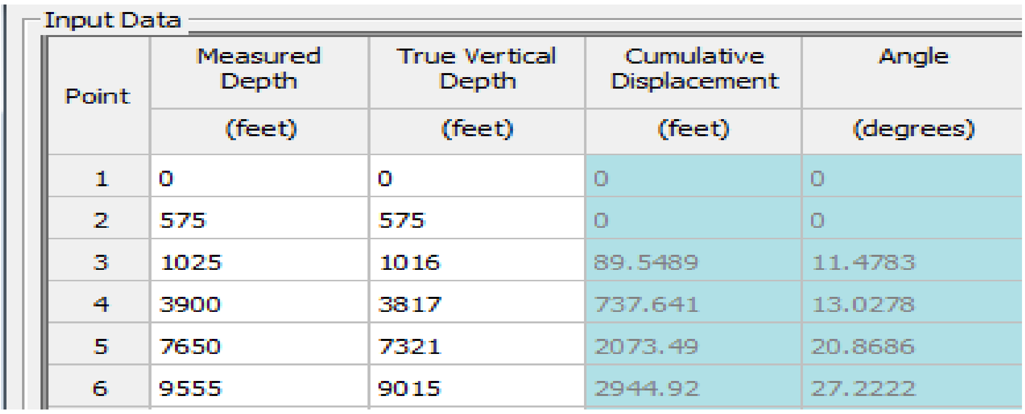
Table 1 PVT Data

Temperature	**200 F**
Bubble Point	3250
Solution GOR	725
Gas Gravity	0.7
Oil Gravity	37 API
Water Salinity	69000ppm
Oil Viscosity	0.368 rb/stb
Oil FVF	1.41 cp

After matching best fit for bubble point, solution gas ratio and oil formation factor correlated with 'Glaso' while best fit for oil viscosity correlated with 'Beet et al'.

- *Equipment Data*

This is next to be inputted into the program database giving allowance for geothermal gradient to calculate pressure and temperature along the well and also the deviation survey can be inputted in this section.



Input Data

Point	Measured Depth (feet)	True Vertical Depth (feet)	Cumulative Displacement (feet)	Angle (degrees)
1	0	0	0	0
2	575	575	0	0
3	1025	1016	89.5489	11.4783
4	3900	3817	737.641	13.0278
5	7650	7321	2073.49	20.8686
6	9555	9015	2944.92	27.2222

Fig 5 Deviation Survey

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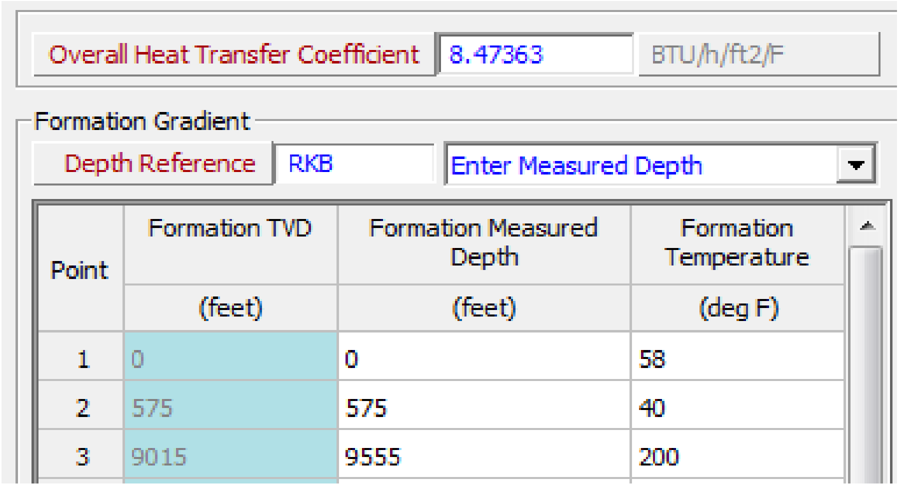

Overall Heat Transfer Coefficient | 8.47363 | BTU/h/ft2/F

Formation Gradient

Depth Reference | RKB | Enter Measured Depth

Point	Formation TVD (feet)	Formation Measured Depth (feet)	Formation Temperature (deg F)
1	0	0	58
2	575	575	40
3	9015	9555	200

Fig 6 Geothermal Gradient

- *Table 2: IPR Data*

The Darcy model was used for the calculation of IPR curve and then validated with the test data in as gotten from the field for accurate enhancement of the built model which will be used to predict well A03 performance.

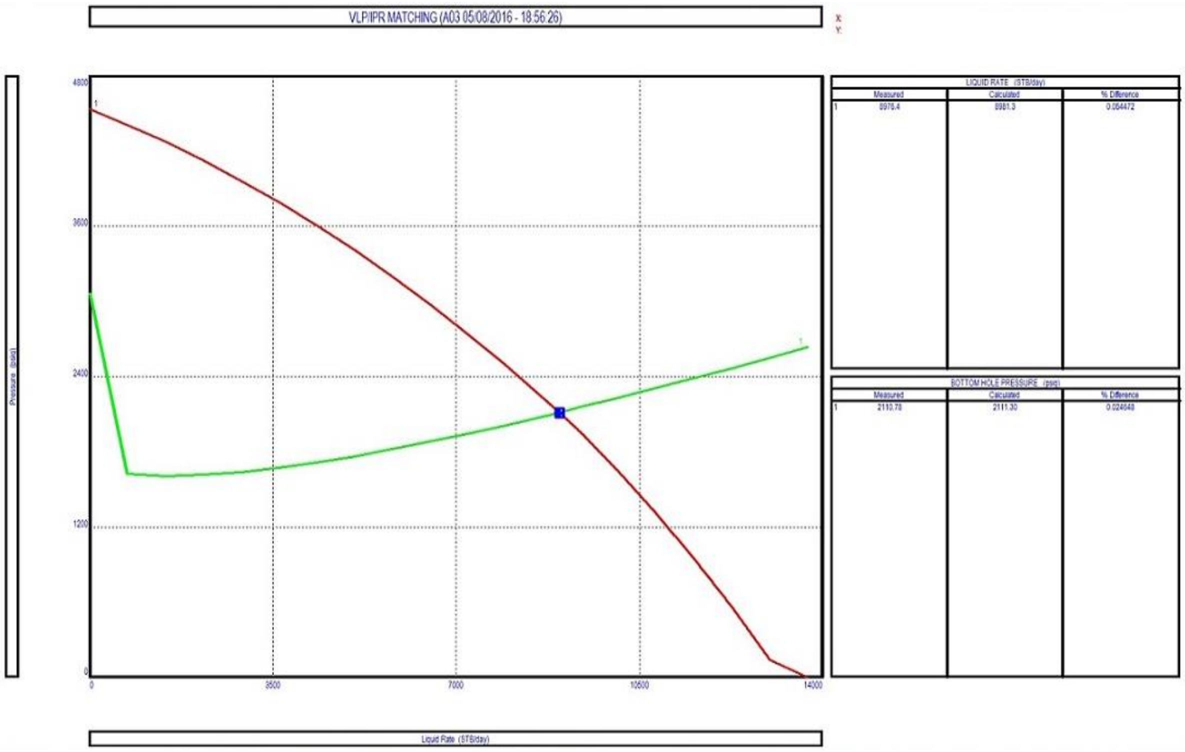

Fig 7 VLP/IPR Matching with Well A03 Test Data

The curve from Fig shows an AOF potential of 13722.0 STB/day with a P.I of 9.04 STB/day/psi. The skin which is 2.85 was automatically calculated by the skin model karakas + Tariq / Cinco (2) / Martin-Bronz.

From the case study, Well A03 has produced for a period of time and water cut has increased, dropping reservoir pressure and also rate of production has massively dropped. Fig shows that the VLP and IPR curve does not intercept which indicates a complete production decline at 70% water. Therefore, the need of a continuous gas lift system was implemented to increase production.

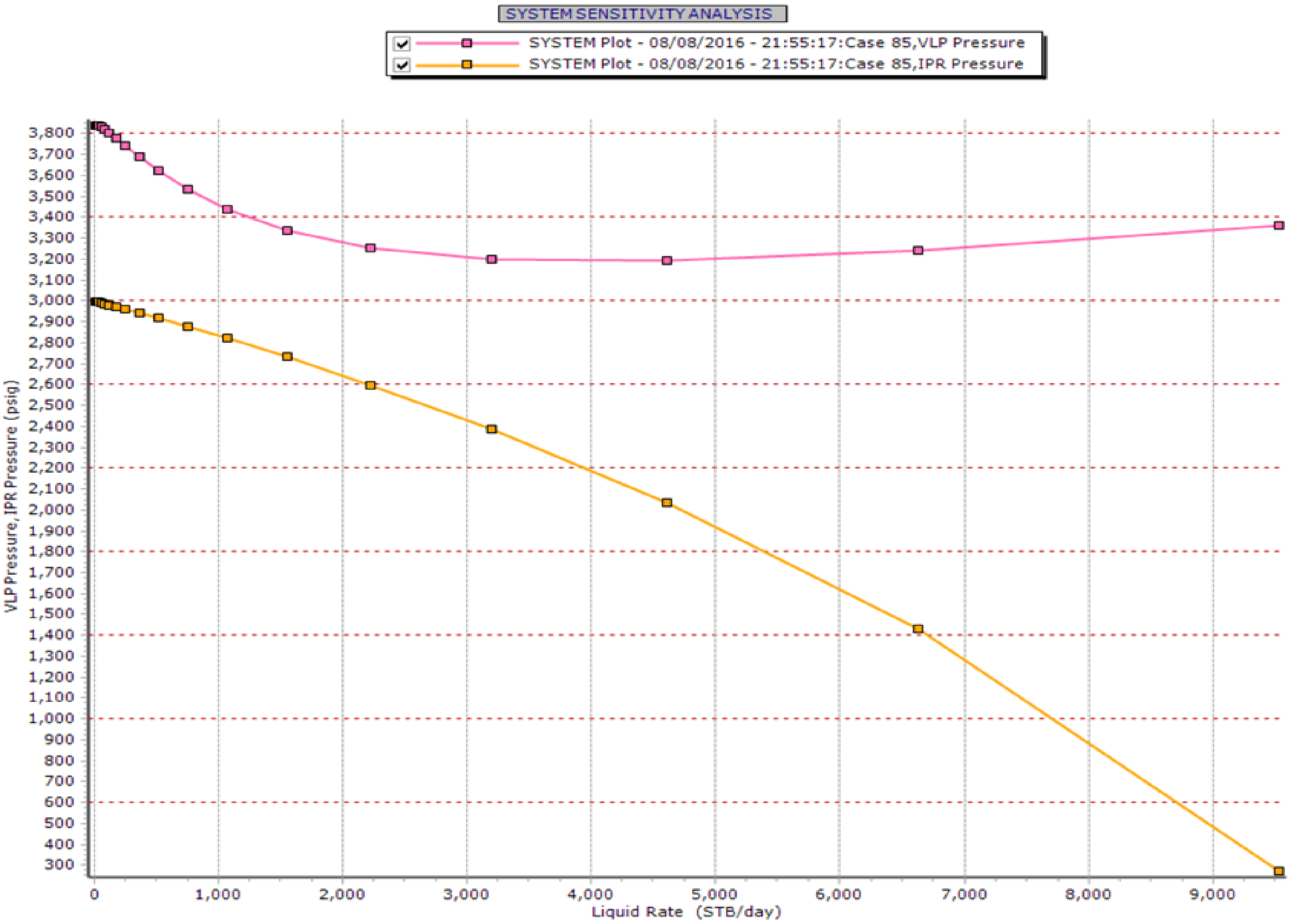

Fig 8 VLP/IPR Curve at 70% Water Cut

- *Simulate Base Case Forecast under Various Conditions*
  After matching PVT, VLP and IPR data, scenarios were made to use the model to perform a system analysis.

✓ Sensitivity test was carried out on the reservoir pressure for decrease and increase in wellhead pressure.
✓ Reduction in wellhead pressure reduces the drawdown pressure which in turn increases the oil production as seen in Table 2 and graphically represented in Fig . (The absence of 520psig wellhead pressure line is as a result of no production for the specified water cut cases).

Table 2 Reservoir Pressure 3500psig

WATER CUT (%)	**50**	**60**	**70**
WHP (PSI)	Oil Rate (stb/day)		
260	2439.22	1562.35	672
330	2094.95	1237.78	0
520	0	0	0

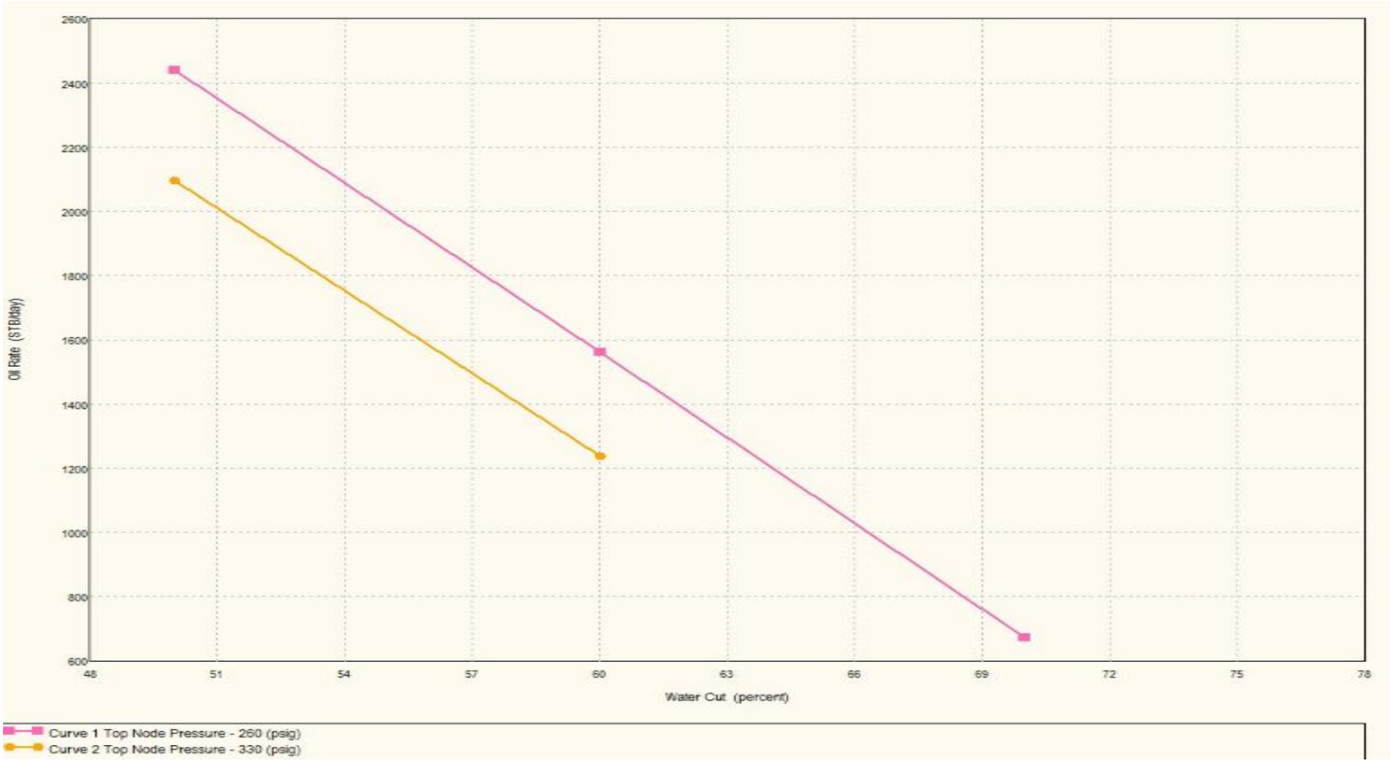

Fig 9 Sensitivity Plot of WHP 260, 330 & 520

- *Performing The Gas Lift Design for Well A03*

Enabling the artificial lift system to a gas lift continuous system will be the first change made on this model for gas lift design to be accessed. (Then update the required sections with additional options due to the new change).

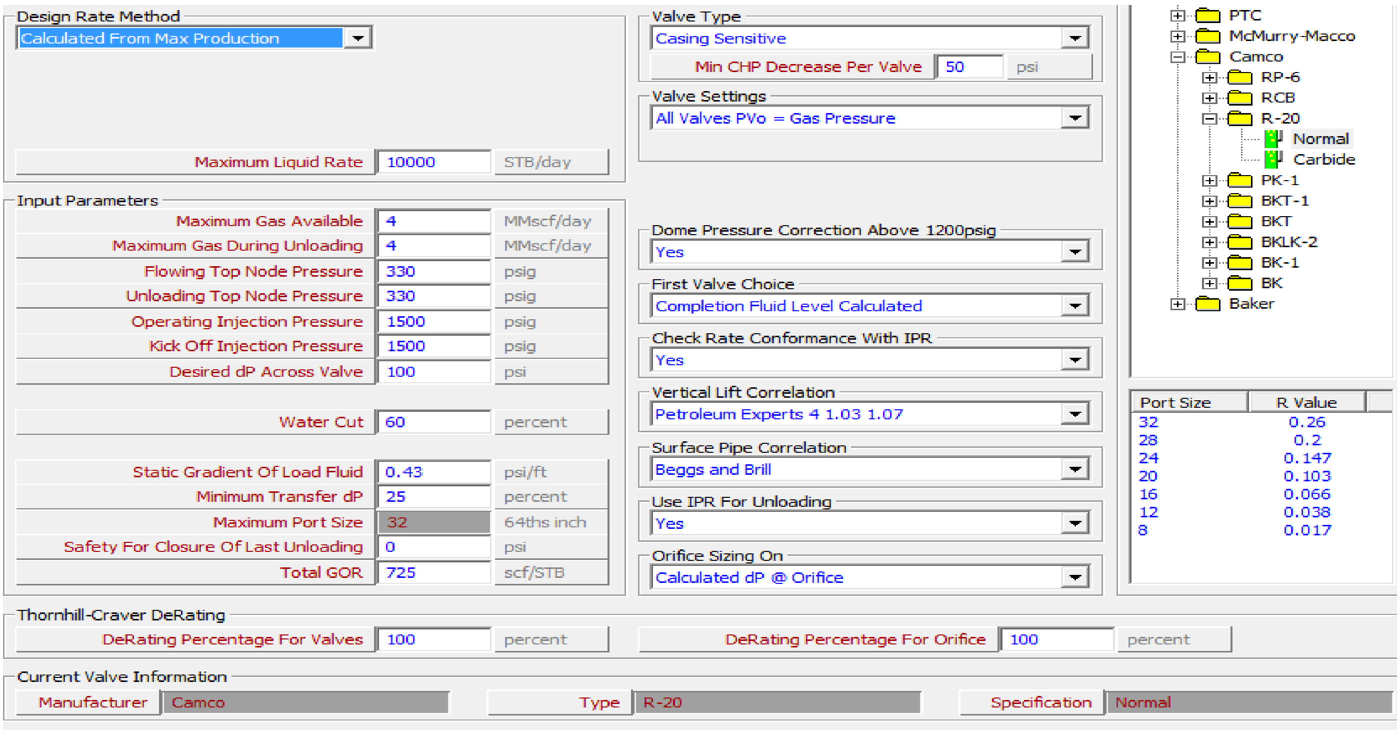

Fig 10 Performing The Gas Lift Design for Well A03

- *Gas Lift Valve Port Size Adjustment*

After designing the gas lift system, the valve port size was check and adjusted to observe the effect it has on oil production. The various types of valve in Prosper database were tested to observe if there will be a change in oil production. Though from my research done, prosper by default will pick the optimal valve port size required to give maximum production, since the valve type is casing sensitive.

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The valve type Camco R-20 Normal is used to run the gas lift design having a maximum port size of 32 and a minimum of 8 as seen in Fig, so many other valve will be tested to observe the change in production.

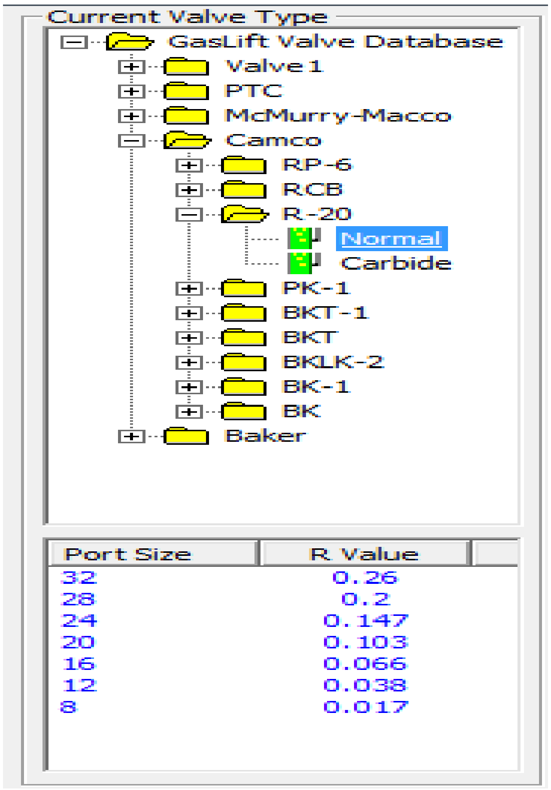

Fig 11 Valve Types

C. Parameters for Well A04

Basically, the procedures used in achieving the optimum gas lift rate for well A03 will be applied for this other well despite the variation in some of the parameters.

Table 3 PVT Data

Temperature	**200 F**
Bubble Point	3250
Solution GOR	739
Gas Gravity	0.7
Oil Gravity	37 API
Water Salinity	69000ppm
Oil Viscosity	0.358 rb/stb
Oil FVF	1.412 cp

- *Run Quality Check of PVT Data*

Table 4 Test Data

Tubing Head Pressure	**450 Psig**
Tubing Head Temperature	134.2 F
Water Cut	10%
Liquid Rate	8012.34 stb/day
Gauge Depth (measured)	6350 feet
Gauge Pressure	1689.2 psig
Reservoir Pressure	3625.78 psig
GOR	739 scf/stb
GOR Free	0

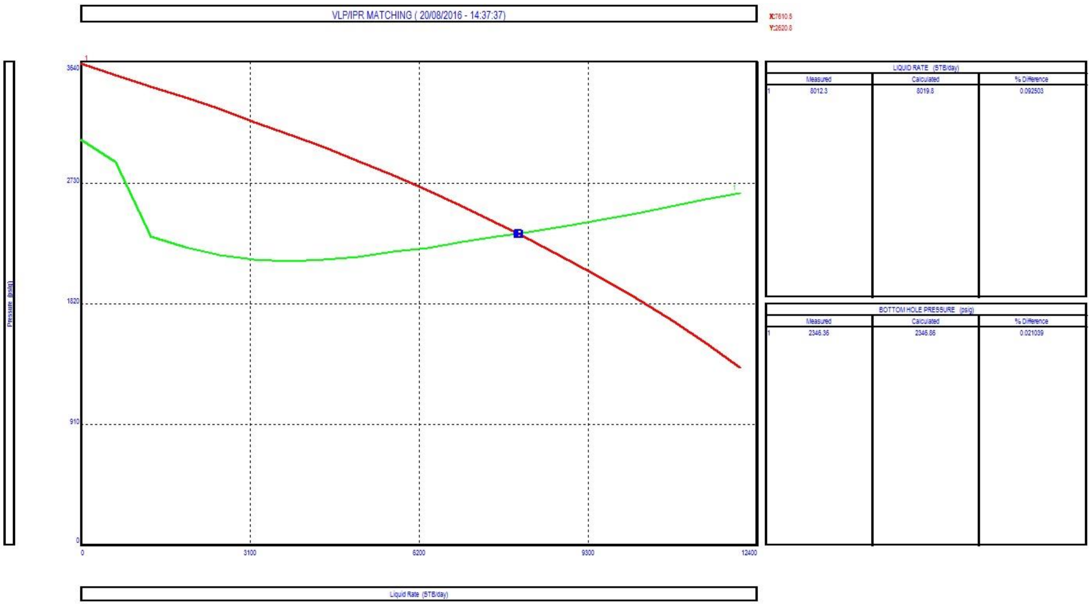

Fig 12 VLP/IPR Matching with Well A04 Test Data

The VLP/IPR curve in appendix 1 shows an AOF of 12100.9stb/day and a P.I of 9.77stb/day/psi, with skin 1.34.

The sensitivity plot below, shows that well A04 seizes to produce at 60% water cut at a well head pressure of 330psig, which calls for assistance of an artificial lift system.

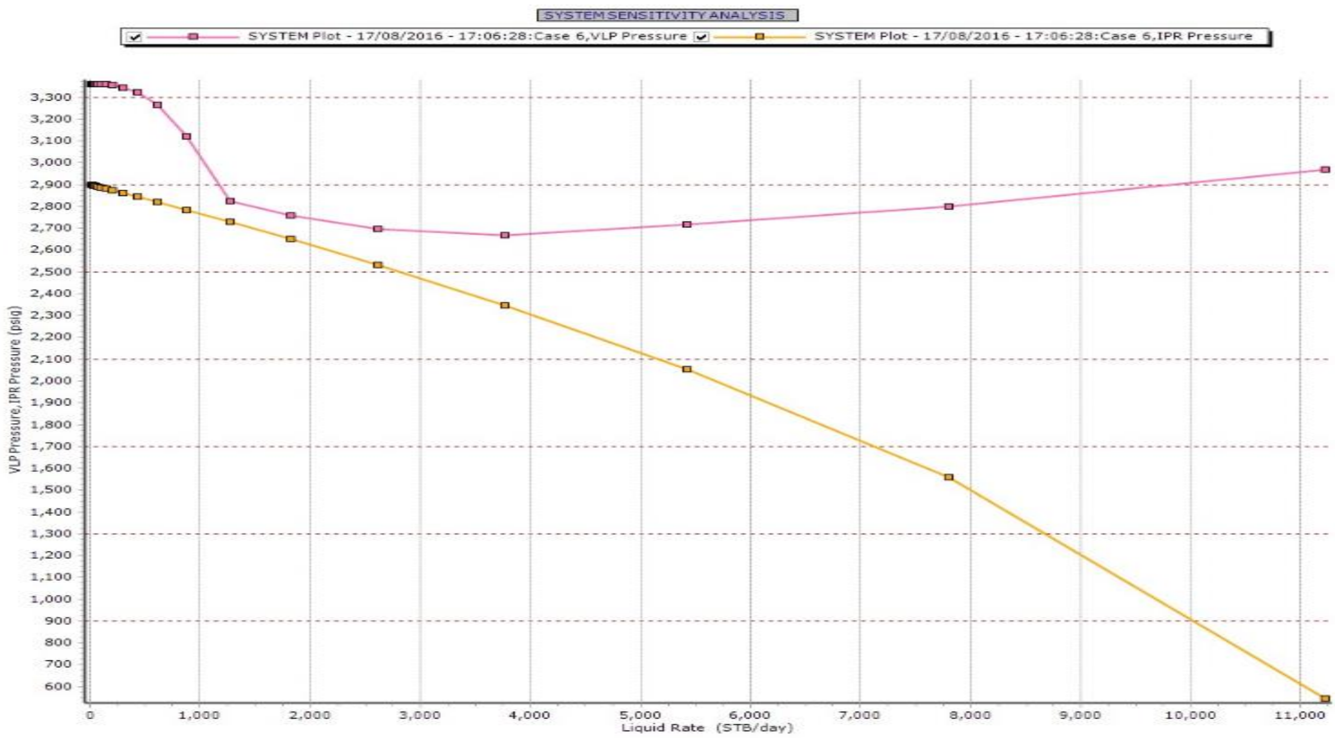

Fig 13 VLP/IPR curve at 60% water cut (Well A04)

Table 5 Reservoir Pressure 2900psig

Water Cut (%)	**40**	**50**	**60**
WHP (psi)	Oil Rate (stb/day)		
260	2847.6	1989.27	858.838
330	2432.99	1404.08	0
520	0	0	0

Table and shows the different production rate for different scenarios of well A04, which will be used to compare and see if

Water Cut (%)	**40**	**50**	**60**
WHP (psi)	Oil Rate (stb/day)		
260	2847.6	1989.27	858.838
330	2432.99	1404.08	0
520	0	0	0

the use of continuous gas lift system will be a more profitable option.

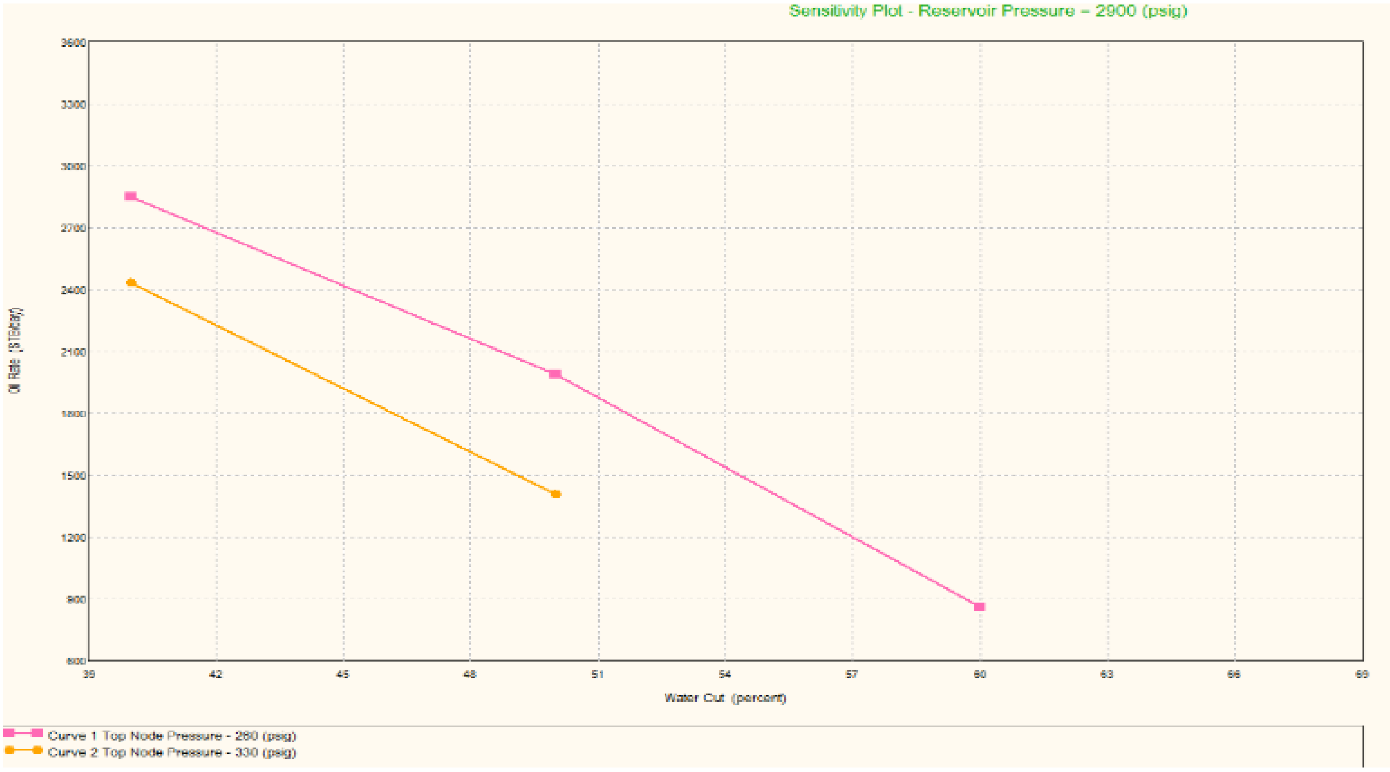

Fig 14 Sensitivity Plot of WHP 260, 330 & 520

➢ *Performing Gas Lift Design*

Similar steps used in well A03 was applied for the design of the gas lift system that will yield optimum gas injection rate for the well A04 though some parameters changed like the maximum depth and water cut.

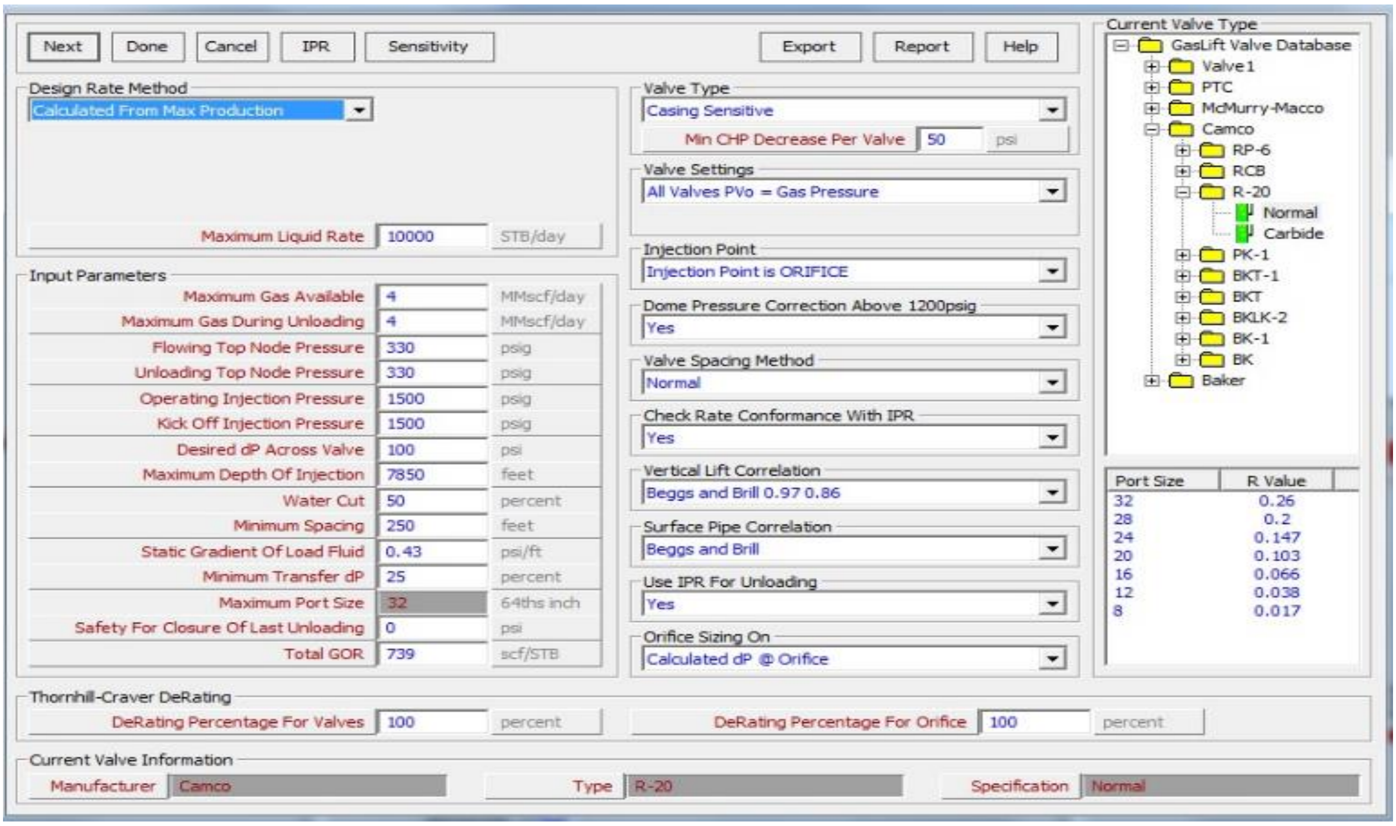

Fig 15 Design Parameters

➢ *Valve Type Adjustments*

Also, adjustments were made using the available valve type provided in the prosper database to observe and see if the rate of production will be altered. Which was done by highlighting the type of valve to be used and calculating and observing the changes to be made. Notes where taken down and discussed for valve types that affected the rate of production.

V. RESULTS AND DISCUSSION

➢ *Result of Gas Lift Design (Well A03)*

From the gas lift performance curve in Fig the designed maximum injection gas rate is 4MMscf/day which can be seen in the design parameters in figure 16 will yield an oil production of 2170stb/day, the plot also shows that continuous increase in gas rate with yield more production, as an increase in gas injection with turn the fluid lighter making it easy to travel though it reaches a point where any further gas injection increases the frictional component more than it will decrease gravity component, thus production rate drops (Ezekiel, et al., 2015). The maximum oil production of 2634.75stb/day will be for gas lift rate of 13MMscf/day, which represents the optimum gas lift rate of well A03. In situations where the available gas is higher than the optimum gas the system will only inject the optimum gas into the well. The diagram in Fig shows the plot of oil rate (stb/day) against gas injected rate (MMscf/day), using this plot, the engineer is provided with quick information concerning the rate of oil that can be produced when a certain amount of injected gas goes into the well. This diagram can only be created after the gas lift design has being calculated.

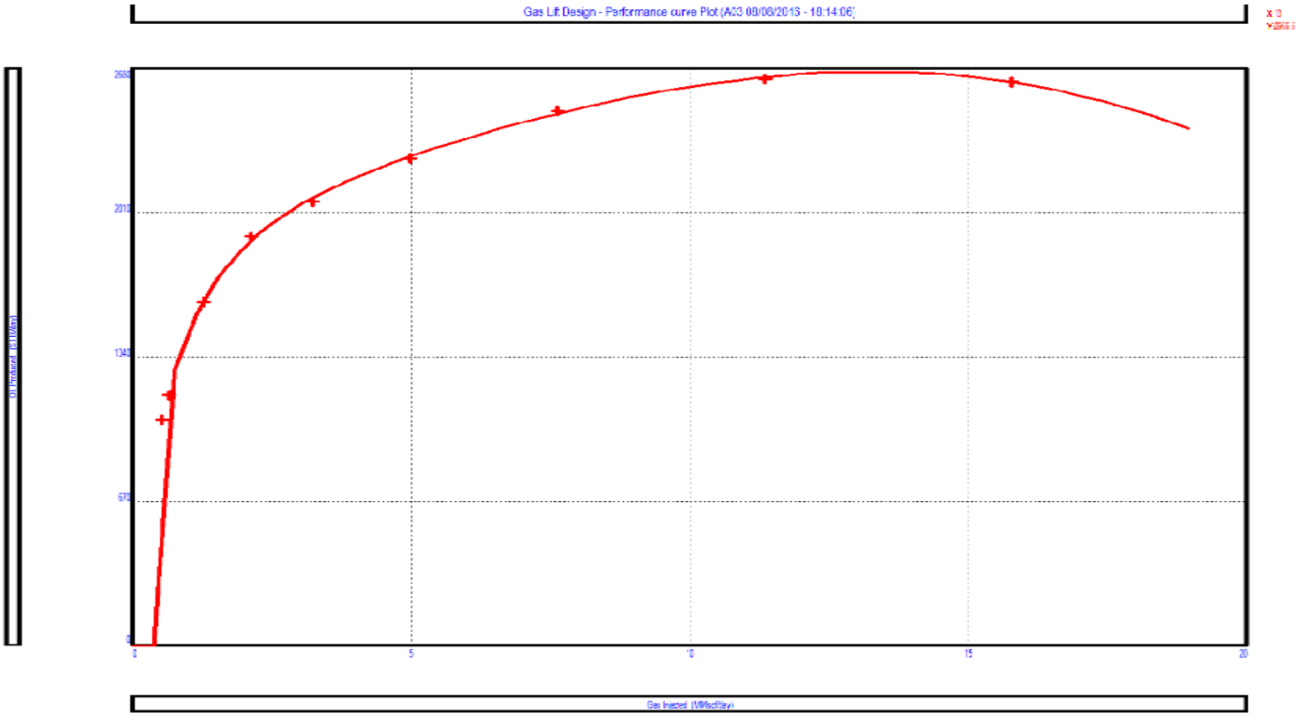

Fig 16 Gas Lift Performance Curve

- *Sensitivity Analysis*

For a system to be proven effective it is mandatory to carry out sensitivity test for some key parameters affecting the productivity of the well that is to be optimized. Some of these parameters include water cut, pressure, gas injected rate and valve port sizes.

For better understanding of the present and future scenario of the continuous gas lift, (well A03) will be compared to the natural flowing (well A03) data as seen in Table 2 a sensitivity analysis was carried out for the cases seen below and results shown in Figure 16.

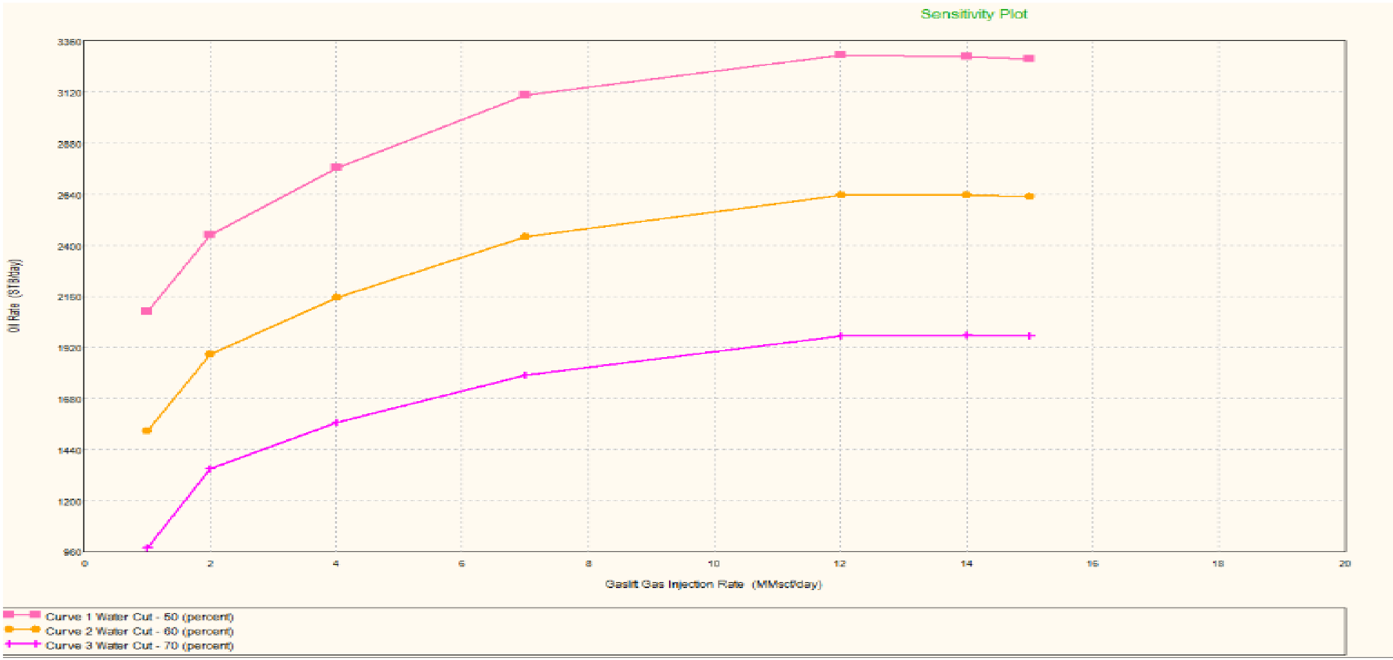

Fig 17 Sensitivity Plot of water cut (%) 50, 60 & 70 @ WHP 330psig

Judging by the sensitivity plot provided in Fig as water cut increases it is seen that the rate of injected gas needed to attain optimum production slightly increases.

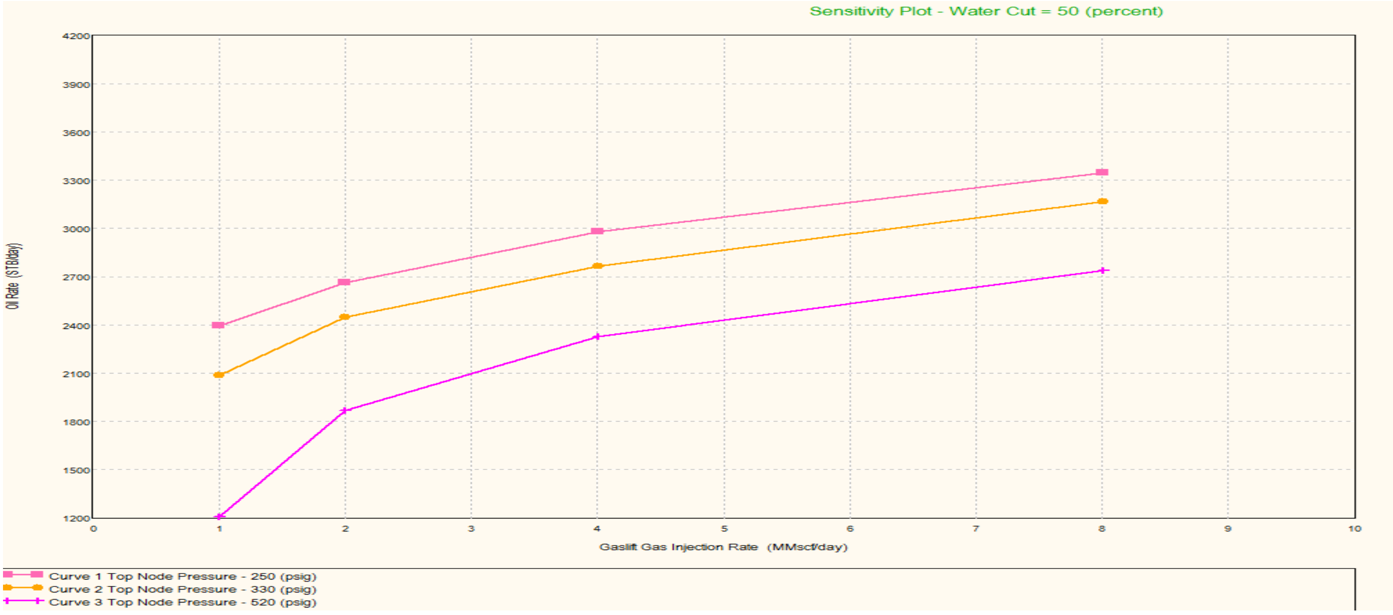

Fig 18 Sensitivity Plot of Wellhead Pressure (260, 330, 520psig).

Sensitivity analysis for different well head pressure is seen above in
Fig . This explains what happens if the well head pressure is increased or reduced. From the plot it is clear that increasing the wellhead pressure will reduce production and decreasing the wellhead pressure will increase production.

Table 6 Reservoir Pressure 3000psig, WHP 330psig

Water Cut (%)	50	60	70
No. Gas Injected (MMscf/day)	Oil Rate (stb/day)		
1	2089.48	1531.83	990.782
2	2450.4	1892.36	1336.7
4	2765.22	2156.83	1565.62
12	3297.15	2633.96	1968.06
13	3295.97	2634.75	1970.82
14	3289.65	2631.18	1970.02

Comparing the results in Figure 16 with the case study result in Table 2 well A03 oil production was 1237.78stb/day at 60% but with the implementation of a continuous gas lift system, oil production rises to 2156.83stb/day at a designed gas injected rate of 4MMscf/day at 60% water cut. Though further increase of gas injected yielded more production rate until a stage of gas injection rate 14MMscf/day where increase in frictional component was more than it decreases gravity which led to a drop-in production. More so from Figure, Well A03 is in its natural flow, we can see there was zero production at 70% water cut but with the support of a continuous gas lift system production rate appreciated to 990.782stb/day at a gas injection rate of 1MMscf/day and at a much reduced reservoir pressure. Although increase in gas injection rate led to higher production rate until a gas injection rate of 14MMscf/day where production dropped.

From the sensitivity plot in Figure 17 together with Table 7 as the wellhead pressure increases production drops, therefore for higher production rate it is required that the well-head pressure be reduced.

- *Gas Lift Valve-Type Port Size Effect Well A03*

Table 8 Valve: Camco R-20 Normal

Valve Type	Valve Depth (ft.)	Port Size (64^{th} inch)	Gas lift Gas Rate (MMscf/day)
Valve	3526.13	8	0.38982
Valve	5813.9	16	1.80491
Valve	7292.11	24	3.02159
Valve	8090.92	28	3.62375
Orifice	8389.29	31	3.89823
Oil Rate of 2153.77stb/day			

Table 7 Valve: Camco BKLK-2 Carbide

Valve Type	Valve Depth (ft.)	Port Size (64^{th} inch)	Gas lift Gas Rate (MMscf/day)
Valve	3526.13	6	0.38216

Valve	5813.9	12	1.76252
Valve	7292.11	12	0.88193
Valve	8090.92	12	0.6634
Orifice	8389.29	12	3.8216
Oil Rate of 2137.62stb/day			

Table 8 Valve: Camco RP-6 Normal

Valve Type	Valve Depth (ft.)	Port Size (64^{th} inch)	Gas lift Gas Rate (MMscf/day)
Valve	3526.13	16	0.38982
Valve	5813.9	16	1.80491
Valve	7292.11	24	3.02159
Valve	8090.92	28	3.62375
Orifice	8389.29	32	3.89823
Oil Rate of 2153.77stb/day			

Various valve types were tested and calculated to observe the change in production, nearly all the valve types in Prosper database calculated the same result for oil rate except the Camco BKLK-2 Carbide which gave a slight reduction in oil rate. The results are analysed below;

- Camco R-20 normal: Have a variety of port sizes which increases as the depth increase down the wellbore and for every valve depth Prosper selects the best and convenient port size that will permit the optimum injected gas rate for that particular depth. From Table 8 as the port size increases down the depth also did the gas injected rate increased, thus allowing this particular valve to accept more injected gas which resulted to an oil rate of 2153.77std/day.
- Camco RP-60 normal: This also comes in different port sizes and from Table 10 the first port size produced the same amount of injected gas with the first port size in Table 8 , though the port sizes are not the same when compared in the tables mentioned, but this result shows that, the maximum rate of injected gas that can be accepted at depth 3526.13ft is 0.38982MMscf/day. The other port sizes remained the same and produced the same amount of injected gas as seen in Table 8 which gave an oil rate of 2153.77std/day.
- Camco BKLK-2 Carbide: This valve does not possess so much variety in terms of port sizes, the port sizes are 6 & 12. Prosper makes use of the port sizes and accepts the best fit for each depth. Looking at Table 9 the first port size selected by Prosper is 6 which resulted in a gas injected rate of 0.38216MMscf/day which is slightly lower when compared to the gas injected rate produced by port sizes (8 and 16) in the tables above. Going down the valve depth the port size selection increased to 12 which is the maximum port size for this valve but the rate kept reducing when compared to the rate of injected gas in the previous two tables mentioned. The difference in gas injected rate appears to be wide which means the larger port sizes seen in Table 8 and Table 10 played a significant role by allowing more injected gas to be passed through their port sizes than Camco BKLK-2 port sizes.

➢ *Result Discussion (Well A04)*

From the diagram in Fig, optimum gas injection rate is 7MMssf/day which gave maximum production of 2756.55stb/day and the maximum rate of 4MMscf/day calculated an oil production of 2627.8stb/day but after design the oil produced resulted to 2496.37stb/day at an optimum injection rate of 3.2279MMscf/day.

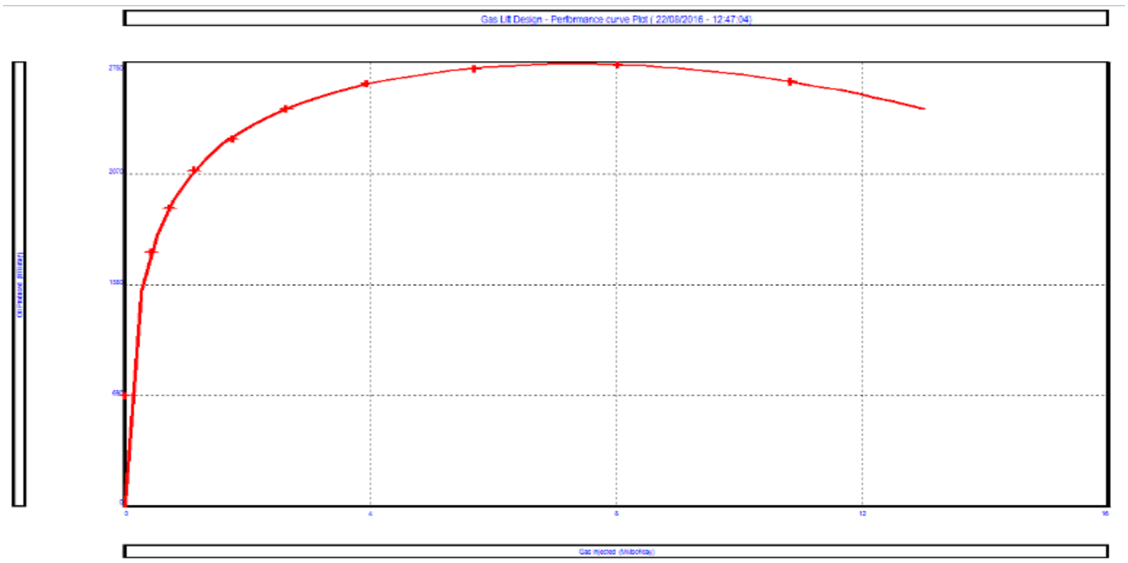

Fig 19 Gas Lift Performance Curve

- *Sensitivity Analysis Well A04*

Different case scenarios are being created to see how the well will perform when the well head pressure is increased or reduced at different water cut intervals. The cases are being represented in a plot as seen in below in Fig. Also, the effect of gas lift injection rate on production can be seen in Table 11.

Sensitivity study shows that at 60% water cut production tend to exist even at the lowest rate of gas injection whereas for a natural flowing well A04 at 60% water cut production seize to exist, which shows the effectiveness and importance of the lift system.

With the plot shown in
Fig, lowering the wellhead pressure will realise more production rates than increasing the wellhead pressure.

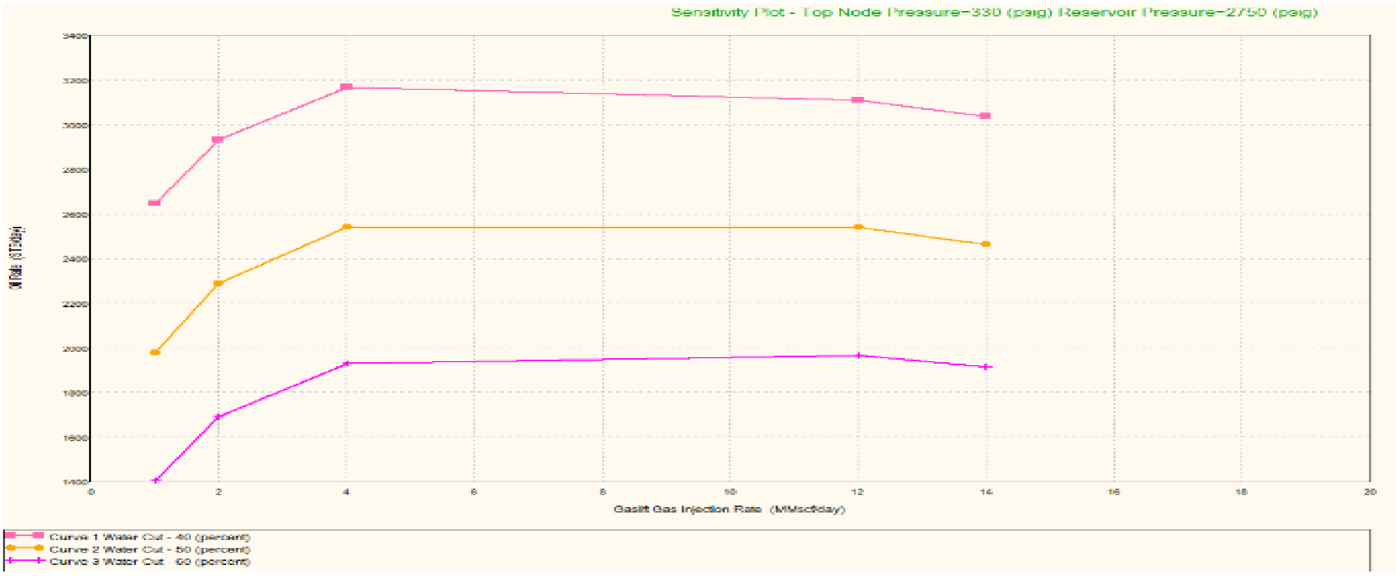

Fig 20 Sensitivity Plot of water cut (%) 40, 50 & 60 @ WHP 330psig

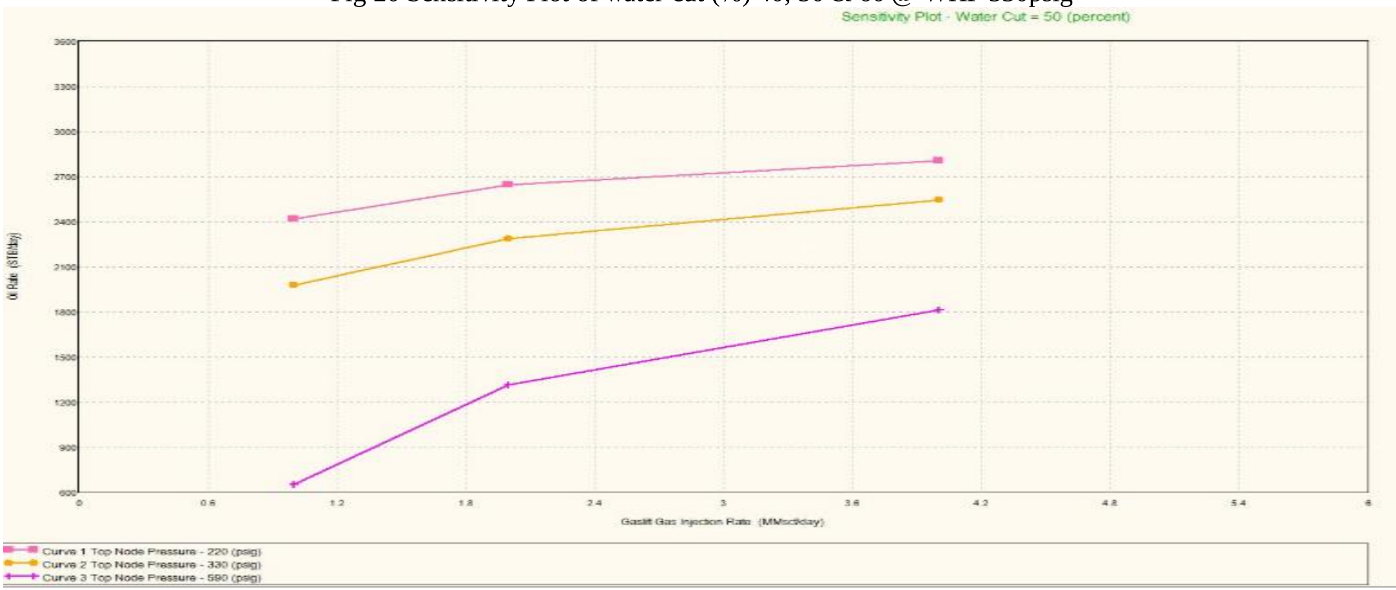

Fig 21 Sensitivity Plot of Wellhead Pressure (220, 330, 590psig)

Table 9 Reservoir Pressure 2750psig WHP 330psig

Water Cut (%)	**40**	**50**	**60**
No. Gas Injected (MMscf/day)	Oil Rate (stb/day)		
1	2645.59	1977.84	1407.56
2	2934.86	2288.81	1692.16
4	3169.53	2544.56	1930.72
12	3109.37	2540.7	1967.43

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The table above shows the rate of gas injection and the oil produced at different water cuts. Production rate has improved compared to the initial production at 50% water cut for well A04. The initial production for well A04 at 50% water cut is 1404.08stb/day without gas lift, but with the implementation of gas lift at water cut 50% the production increased to 2544.56stb/day at 4MMscf/day. Though continuous increase in gas rate above 7MMscf/day resulted to a drop-in production. This drop-in production after an initial increase in production can also be seen for the other cases stated in the table above.

- *Gas Lift Valve-Type Port Size Effect Well A04*

Table 10 Valve: Camco R-20 Normal

Valve Type	Valve Depth (ft.)	Port Size (64th inch)	Gas lift Gas Rate (MMscf/day)
Valve	3530.41	8	0.33228
Valve	5447.76	12	1.00497
Valve	6485.93	20	2.03307
Orifice	6929.45	28	3.32279
Oil Rate of 2496.37stb/day			

Table 11 Valve: Camco BKLK-2 Carbide

Valve Type	Valve Depth (ft.)	Port Size (64th inch)	Gas lift Gas Rate (MMscf/day)
Valve	3530.41	8	0.31382
Valve	5447.76	12	0.84228
Valve	6485.93	12	0.79881
Orifice	6929.45	28	3.13821
Oil Rate of 2443.81stb/day			

Table 12 Valve: Camco RP-60 Normal

Valve Type	Valve Depth (ft.)	Port Size (64th inch)	Gas lift Gas Rate (MMscf/day)
Valve	3530.41	16	0.38148
Valve	5447.76	16	1.22898
Valve	6485.93	20	2.47078
Orifice	6929.45	28	3.81479
Oil Rate of 2496.37stb/day			

Similar with the valve type test carried out for well A03, the same was done to see if the slight change in production will occur using BKLK-2 carbide valve type.

- Camco R-20 normal and Camco RP-60 normal: From the results given in Table 12 and Table 14, both valve types gave the same result though their port sizes at different depths differ, but the allowed maximum gas rate injection at different depths were the same since the port size was large enough to accept that particular amount of gas injected at that depth.
- Camco BKLK-2 Carbide: the port size tends to be too small to accept a high amount of injected gas like the Camco R-20 normal and Camco RP-60 normal. This limitation of allowing high injection gas lift to go through the port size at each depth gave a lower rate in the oil produced.

The Valve depth for Well A04 can be seen in Appendix B shows the different depth point for each valve at the point of design.

➢ *Economic Evaluation*

It is ideal that for every business the profit-making aspect should be properly analysed since that is the key factor to why the business was established. Therefore, before making a final decision based on the implementation of gas lift system a thorough economic analysis should be done, whether it is profitable or not.

For the purpose of this work, we shall be making economic references based on the amount of gas injection to the oil produce, which can be achieved by identifying the profitable gas rate injection that will yield good production and at the same time be beneficial to the company.

Estimated cost of oil per barrel is $51.50 and the estimated cost of gas is $3.71 per Mscf, where 1000Mscf = 1MMscf, which means the cost of gas will be $3710 per MMscf. (U.S Energy Department, 2010). With these figures, comparison can be done to know the gas injection rate that will be beneficial economically.

Table 13 Well A03 Gas Rate Comparison

Gas Injected Rate (MMscf)	Cost of Gas Injected ($)	Oil Produced (stb/day)	Cost of Oil ($)
4	14840	2156.83	111076.745

12	44520	2633.96	135648.94

Table 14 Well A04 Gas Rate Comparison

Gas Injected Rate (MMscf)	Cost of Gas Injected ($)	Oil Produced (stb/day)	Cost of Oil ($)
4	14840	1930.72	99432.08
12	44520	1967.43	101322.645

Table 15 Most Economic Gas Lift Rate

Well Type	Gas Injection Rate (MMscf/day)	Oil Output (stb/day)
A03	4	2156.83
A04	4	1930.72

From the tables above, it is economically unadvisable to go above the injection gas rate of 4mmscf/day, though the plots in Fig and Fig gives an optimum gas rate of 13MMscf/day and 7MMscf/day for well A03 and A04 respectively, but when compared with the most economic gas rate, the oil produce is not worth the increment, which is more than tripling the economic gas rate for both cases (well A03 and A04).

On the other hand, comparing the income realised without gas lift system and with gas lift system will determine if the operation is at a loss or a profit-making firm.

Table 16 Natural Flow

Well Type (woc)	Oil Rate (stb/day)	Oil Cost ($) Daily
Well A03 (60%)	1237.78	63745.67
Well A04 (50%)	1404.08	72310.12

Table 17 Gas Lift at Injection Rate 4MMscf/day

Well Type (w oc)	Oil Rate (stb/day)	Oil Cost (S) Daily
Well A03 (60%)	2156.83	111076.745
Well A04 (50%)	2544.56	131044.84

- *Difference*

Well A03 = 111076.745 – (63745.67 + 14840) = $32491.075 (daily profit)

Well A04 = 131044.84 – (72310.12 + 14840) = $43894.72 (daily profit)

Statistically on a daily production rate with the profit figures given above and with a rough estimate of five (5) to seven (7) years a good capital must have been realised to offset the cost of setting-up this project. On this note, the project is said to be profitable.

VI. CONCLUSION

Using the prosper simulation software with the implementation of the continuous gas lift system the production level for well A03 and well A04 is proven to have risen and the optimum gas injection rate for the two wells were obtained. Achieving the optimum gas rate is very important since going above the above the optimum gas rate will bring about financial loss which is as a result of the drop-in production.

PVT data, IPR curve, downhole equipment, temperature profile, and the gas lift design where carried out without issues with the help of prosper simulation software.

Well A03 with a well head pressure of 330psig gave an increase in production after the implementation of the lift gas system, with an optimum gas lift rate of 13MMscf/day, giving an oil rate of 2666.6stb/day which when compared with the gas injection rate of 4MMscf/day producing at 2156.83stb/day gave a difference of 509.77stb/day, the difference given is not economically attractive when compared to the amount of gas injected, which implies maintaining a gas rate of 4MMscf/day will be economical. Also, Increasing the well head pressure above 330psig resulted to a drop-in production and reducing the well head pressure resulted to an increase in production which was done using the sensitivity plot.

Well A04 also gave rise in oil production when compared to its initial production rate when the gas lift system was yet to be implemented at a well head pressure of 330psig. The optimum gas rate was obtained at 7MMscf/day yielding an oil rate of 2756.55stb/day and with the maximum design gas rate of 4MMscf/day giving 2635.8std/day of oil, comparing the two injecting rate it still economical to stick with the design rate of 4MMscf/day. Similar to Well A03, increasing well pressure will reduce production and reduce well head pressure will increase production.

For further optimization, port sizes of the valves where adjusted for well A03 and Well A 04, with valve type BKLK-2 carbide producing a lower oil rate when compared to camco R-20 and RP-6 normal, which resulted in the gas lift design built using the valve type camco R-20 normal for both wells.

Based on financial benefit it is better to implement the continuous gas lift system as the rate of production decreases, since the boost in production will yield reasonable capital that will cover the cost of implementing the lift system and also bring profit to the company.

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