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Effect of Well Completion Configuration and Tubing Sizes on Well Performance

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Abstract

Completion types and tubing sizes have been identified to play a major role in achieving an optimum production rate while utilizing the reservoir energy optimally. Adequate completion helps in optimizing production while minimizing pressure drop and predicting the longest flowing time. In this work, the effect of well completion configuration and tubing sizes on well performance was evaluated with a steady state simulator (PIPESIM®). A wellbore model was built and completed with both casing and liner completions with flow through the tubing and annulus. Sensitivity analysis was run for different tubing sizes for a given completion type and flow configuration on the well performance. Results showed that increase in tubing sizes from 2.441 inches to 2.992 inches for cased hole completion yielded 22.28% increase in production rate and 22.26% increase in production rate when the tubing sizes was increased from 2.441 inches to 2.992 inches for liner completion for tubing flow respectively. For tubing and annular flow, production increased from 4867.531STB/day to 4875.321STB/day for tubing sizes of 4.5 inches to 4.9 inches for liner completion and the same production rate of 4872.075STB/day with tubing sizes of 4.5 inches to 4.9 inches for open hole completion. This work has shown that changing the tubing sizes for optimization should only be considered for cased hole and liner completions with tubing flow configuration because both casing and liner completion methods with tubing and annular flow gave almost the same results as the tubing sizes were changed. Therefore, completion type with tubing sizes should be examined during design of a well to enhance productivity.

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1. Introduction

Well completion is the process of preparing a well for production. It involves tasks such as installing production casing and tubing, perforating, and adding necessary downhole equipment. The primary goal of any well completion strategy, whether for a simple or complex well, is to efficiently extract oil at a reasonable cost (Travers, 1941). The choice of well completion method and tubing size can significantly impact the well's performance, affecting its initial production rate, ultimate recovery, and production lifespan (Flatern, 2015; Kool, 2019). Different methods, such as open hole completions for low-permeability reservoirs, gravel pack completions to enhance fluid flow, and frac pack completions for creating fractures in the rock, offer various advantages and disadvantages. With the increasing use of advanced well completion methods, particularly in deep and ultra-deepwater settings, the impact and cost of well completion is inevitable (Kulkarni et al., 2007). Multiple factors, including petrophysical properties, formation damage, well geometry, well completions, and fluid phases, affect well performance (Yildiz, 2003). The type of wellbore completion can result in radial, spherical, or hemispherical flow patterns near the wellbore.

Tubing size also plays a crucial role in well performance, determining the fluid flow capacity through the wellbore. Larger tubing allows for higher production rates but can be costlier and more challenging to install. For optimal production rates, it's essential to match the tubing size with well requirements. Undersized tubing increases pressure drop, limiting production, while oversized tubing causes slippage, where different fluid phases move at varying velocities (Brown et al., 1990). Traditionally, the rationalize for designing hole structure and selecting production casing sizes is determined by the drilling engineer, followed by well completion operation to determine tubing size (Proano, 1984; Renpu, 2011). The rational tubing size can be chosen using sensitivity analysis based on nodal analysis during the flowing production stage. Unfortunately, many current reservoir simulators do not account for well completion details (Travers, 1941). Ouyang and Huang (2005) emphasized that there exists a disconnect between reservoir simulators and wellbore hydraulics prediction software concerning complex well hydraulics and completion design effects.

Several studies have explored the significance of well completion types and tubing sizes on initial production rates, ultimate recovery, and production lifespan. However, most studies have been hinged on well completion mode. Burton and Hodge (2003) discussed the essential well design issues including the effect of alternative completion techniques on well productivity. Using analytical relationships, the interplay between drilling and completion operations and well flow performance was analyzed. Kinate et al. (2018) developed an analytical and numerical model for predicting the optimum tubing size for a vertical multiphase flow. Their model proved reliable in determining total pressure gradient hence presenting a better well performance curve than most existing models.

Nwanwe et al. (2020) developed a numerical-based model for predicting optimum tubing size for a vertical oil well but did not incorporate variation of completion mode. Molina and Tyagi (2018) investigated the effects of high production rates on well performance for a cased hole gas well using two types of completion schemes: frac pack and gravel pack without varying the size of tubing. Elklhato and Guo (2022) analyzed three types of well completion, frac-packed well with horizontal hydraulic fracture, and a cased-hole gravel-packed with analytical well inflow models and concluded that the frac-packed well produces better than the gravel-packed without any specification of tubing sizes. Bertrand (2008) used nodal analysis for flow rate examination with different tubing sizes and the result showed flow rate decreases for larger tubing size with no reference to the completion type and general well performance. This work used PIPESIM steady state simulator in developing an optimal well completion and tubing systems model to ascertain the effect of different well completion configuration and tubing sizes on well performance.

2. Methodology

2.1 Simulator and Data

The simulator and data used include; PIPESIM steady state simulation software (used because completion type and tubing size are not time dependent), Wellbore deviation survey data, Geothermal gradient data, Inflow Performance Relationship data, Downhole equipment data (packer, SSSVs) data, Wellbore tubular (casing, tubing strings and liner) data.

2.2 Fluid Model

Black oil model was used with gas oil ratio of 500 SCF/STB, gas gravity of 0.77 and an oil API gravity of 35°API.

2.3 Wellbore Tubular

The wellbore tubular data include the casing, liner and tubing strings properties and setting depth that were install in the well. Table 1 shows the casing, liner and tubing strings data.

Table 1. Casing and tubing strings data.

Equipment	To MD	ID	Wall thickness	Wall roughness
	Ft	in	in	in
Casing	6500	5.575	0.525	0.001
Tubing String	5800	2.992	0.217	0.001
Liner	5040	4.607	0.433	0.001

2.4 Deviation survey

The deviation survey is the reference path for all subsequent depth input for downhole equipment data entry. The deviation survey data is shown in Table 2.

Table 2. Deviation survey.

Measured depth (ft)	True vertical depth (ft)
0	0
500	500
1500	1460
2500	2400
3600	3400
4300	3950
5800	5100
6310	5290
6500	5300

2.5 *Geothermal gradient data*

The geothermal gradient data is presented in Table 3.

Table 3. Geothermal gradient.

Measured depth (ft)	Fluid temperature (°F)
0	65
1500	122
5800	156
6500	160

2.6 Downhole equipment

The downhole equipment is the inflow control devices that help in the regulation of fluid flow rate downhole. The downhole equipment data is shown in Table 4.

Table 4: Downhole equipment.

Equipment	Measured depth (ft)	Bean size (in)
SSSV	2000	2.375
Restriction	5000	2.375

2.7 Reservoir inflow data

The reservoir inflow data is presented in Table 5.

Table 5. Inflow performance relationship data.

Properties	Values
IPR basis	Liquid
Fluid entry	Single point
Geometry profile	Vertical
Reservoir model	Well PI
Reservoir temperature	150°F
Reservoir pressure	2700psia
Water cut	0%
Productivity index	4.20959 STB/d-psi
Mid perforation measured depth	6100ft

2.8 Simulation Approach

PIPESIM steady state multiphase flow simulator was used to develop the wellbore model and for the simulation because the parameters investigated is not time dependent.The wellbore model was built by adding downhole tubular and casing string to the well template workflow with the tubing string installed. For the design of a liner completion wellbore model, the well was cased up to 5100ft measured depth (MD) and thereafter a liner was installed from 5040ft to 6500ft.

The geothermal gradient data shown in Table 3 was entered in the heat transfer section of the well template builder. The single option and multiple option were used for the overall heat transfer coefficient and the ambient temperature input. A value of 2 Btu/h/ft^2/°F was entered for the overall heat transfer coefficient and the average heat capacity for oil, water and gas were left in their default values.

For completion, the geometry profile, fluid entry and measured depth were entered. The well productivity index (PI) model with the use of 'Vogel method below bubble point' was selected for the generation of the inflow performance relation (IPR) curve when the reservoir pressure falls below the bubble point pressure. The reservoir pressure, temperature and productivity index were entered and liquid phase was selected as the IPR basis. A black oil fluid model was created using the data shown in Table 5. The Nodal analysis simulation task was implemented and sensitivity run for different tubing sizes on well performance while considering both completion types and flow configurations.

2.9 Design and Wellbore Schematic for different flow configuration

Figure 1 shows a cased hole completion for only tubing flow in which the casing string was run through the production interval and cemented in place. A Tubing string was installed and the annulus between the casing and tubing strings was isolated from fluid production with a production packer.

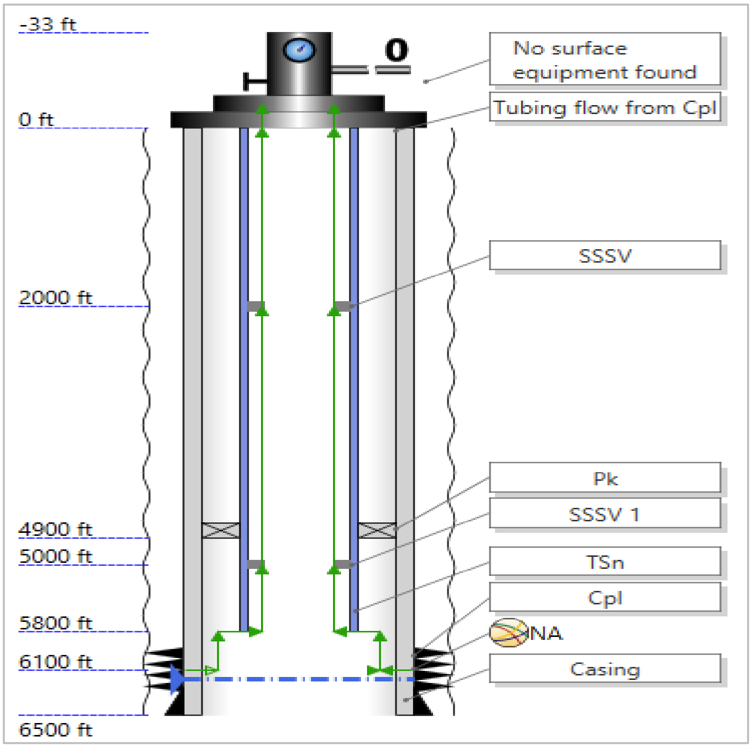

Fig.1. Wellbore schematic for cased hole completion with tubing flow configuration.

The design of cased hole completion, tubing and annular flow configuration was done by running the casing strings through the production interval and cementing it in place and then installing a tubing string with production allow through both the annulus between the casing and tubing strings (without production packer) and through the tubing string. The wellbore schematic for cased hole completion, tubing and annular flow configuration is shown in figure 2.

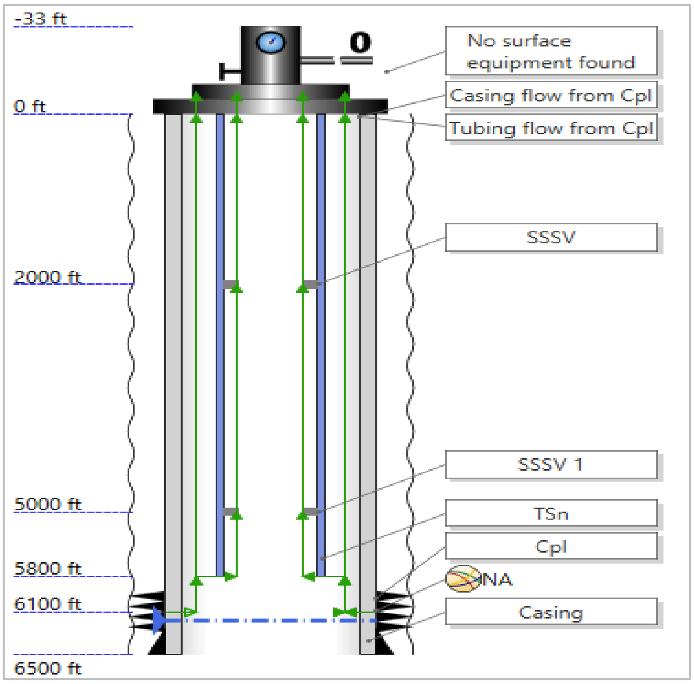

Fig. 2. Wellbore schematic for cased hole completion, tubing and annular flow configuration.

In order to design a liner completion with tubing flow configuration, the casing string was run up to the top of the pay zone and cemented in place. The well was cased up to 5100ft. A liner was set across the production interval starting from 5040ft MD to 6500ft MD and was hung on the wall of the casing string with a liner hanger. A tubing string was installed and the annulus between the casing and tubing strings was isolated from fluid production with a production packer. The wellbore schematic for liner completion with tubing flow configuration is shown in Figure 3.

The design of liner completion with tubing and annular flow configuration was done by running the casing string through the production interval and cementing it in place and then installing a tubing string with production allowed through both the annulus between the casing and tubing strings (without a production packer) and through the tubing string. The wellbore schematic for liner completion, tubing and annular flow is presented in Figure 4.

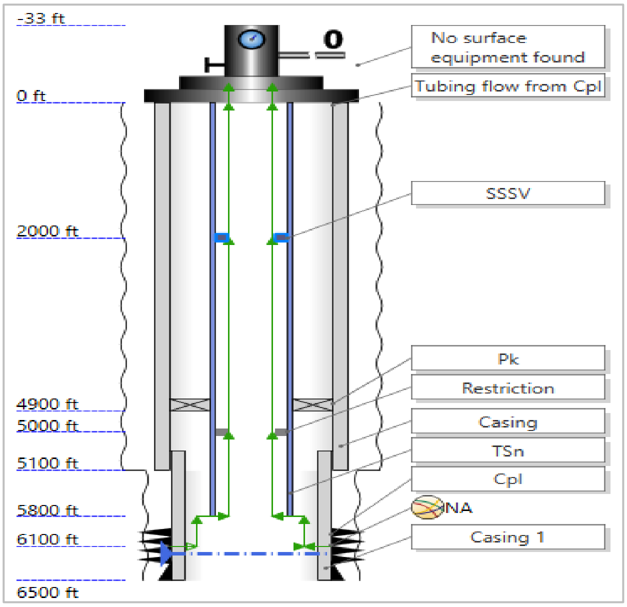

Fig. 3. Wellbore schematic for liner completion with tubing flow.

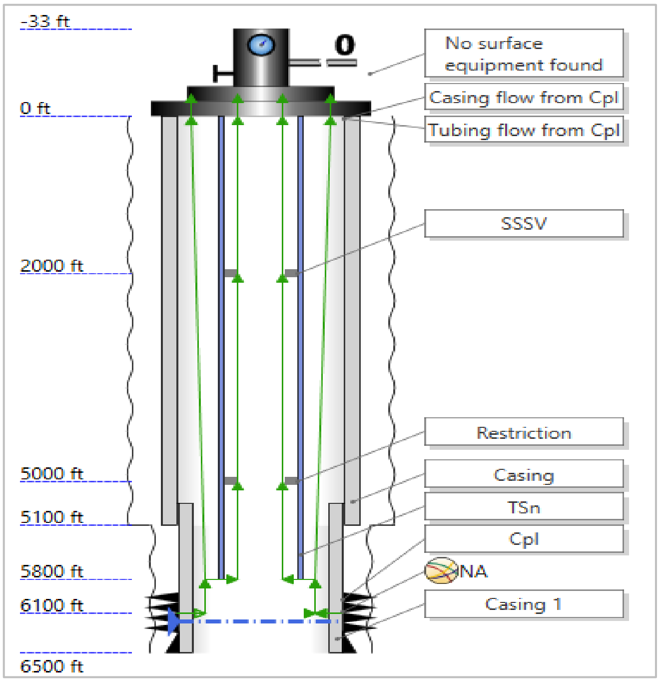

Fig. 4. Wellbore schematic for liner completion with tubing and annular flow.

2.10 Sensitivity analysis

For an effective optimization of a system, it is important to analyze the key parameter affecting the productivity of a well been optimized. In this study, the effect of tubing sizes considering cased hole completion, tubing flow and tubing with annular flow and liner completion with tubing flow and tubing and annular flow were evaluated. Tubing sizes of 2.441, 2.992, 3.992, 4.5 and 4.9 inches were run for each of the well completion types and flow configurations.

3. Results and Discussion

3.1 Effect of tubing sizes on well performance for cased hole completion with tubing flow

Figure 5 shows a downward shift in the intersection between the vertical lift performance and inflow performance relationship curves, which implies an increase in liquid production from the well as the tubing sizes increases.

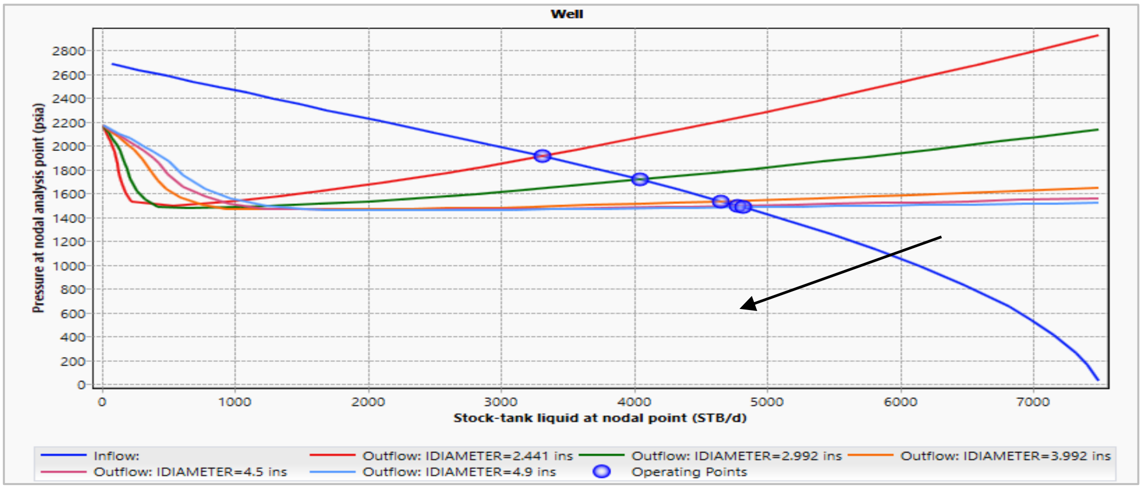

Fig 5. Well performance curve for cased hole completion with tubing flow configuration.

Figure 6 shows the stock tank liquid rate at nodal point (bottom hole) for each tubing sizes for cased hole completion, tubing flow. Results reveal that tubing size increase from 2.441 to 2.992 inches increases the stock tank liquid rate from 3305.529 STB/day to 4041.973STB/day and 3.992-inches to 4654.833STB/day. However, for an increase in tubing sizes from 4.5 to 4.9-inches, the oil flow rate from the well does not increase as much as when the tubing size was increase from 2.441 to 2.992 and 3.992 inches. The effect of increasing the tubing size as long as it is not too large is to achieve a higher top node or wellhead pressure for a given flow rate, as the pressure drop in the tubing will be decreased.

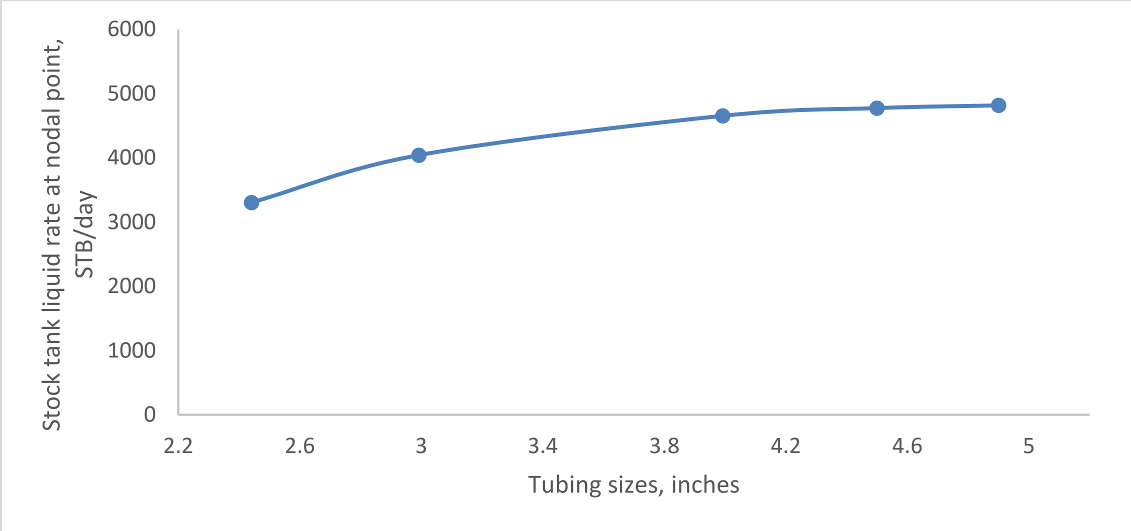

Fig. 6. Stock tank liquid rate at bottom hole for different tubing sizes for cased hole completion, tubing flow.

Figure 7 shows the well bottom hole flowing pressure against the tubing sizes for cased hole completion, tubing flow. Result shows a gradual decline in the bottom flowing pressure as the tubing sizes increase from 2.441 to 2.992 inches. This decline in the flowing bottom hole pressure leads to an increase in pressure drawdown thus giving room for more inflow. Comparing the bottom hole flowing pressure for tubing sizes of 3.992, 4.5 and 4.6 inches indicates a minimal decrease in the flowing bottom hole pressure for those tubing sizes. This confirms the slight increment in production rate shown in Figure 6 for 3.992, 4.5 and 4.6 inches tubing sizes.

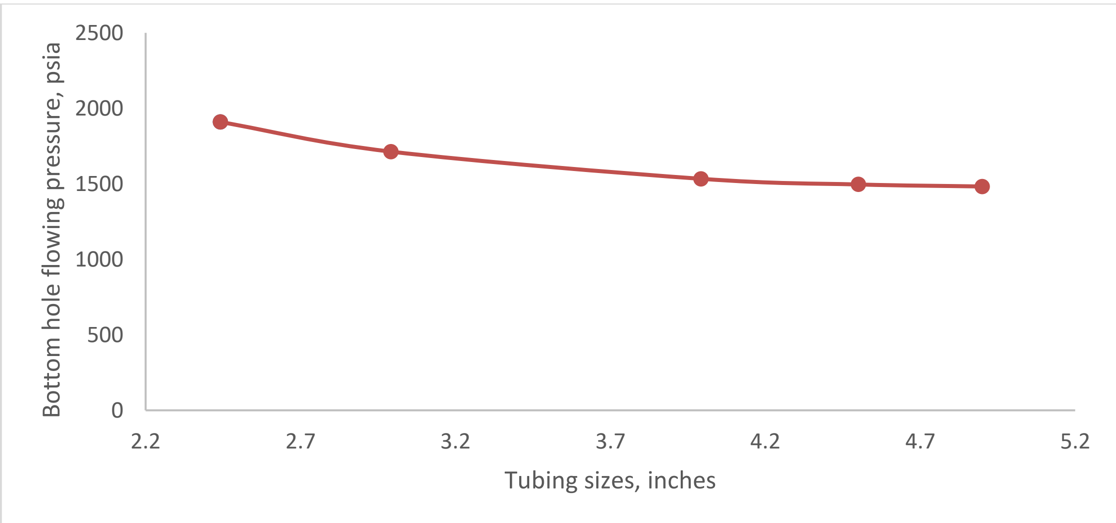

Fig. 7. Bottom hole flowing pressure for different tubing sizes for cased hole completion, tubing flow.

3.2 Effect of tubing sizes on well performance for cased hole completion, tubing and annular flow

Figure 8 shows the well performance curves for different tubing sizes for cased hole completion, tubing and annular flow. Results show a downward shift in the intersection between the VLP and IPR curves as it was for cased hole completion, tubing flow as the tubing sizes increases. There is closeness of the outflow curves for each of the tubing sizes when compared with cased hole completion tubing flow.

Figure 9 shows the stock tank liquid rate at bottom hole for different tubing sizes for cased hole completion, tubing and annular flow. Result shows an increase in stock tank liquid rate as the tubing size was change from 2.441 to 2.992 and 3.992 inches. The increase in the liquid production rate resulted in a decrease in the bottom hole flowing pressure as shown in Figure 9, while it was the same production rate for tubing sizes for 4.5 and 4.9 inches. This confirmed the same bottom hole flowing pressure of 1465.016 psia.

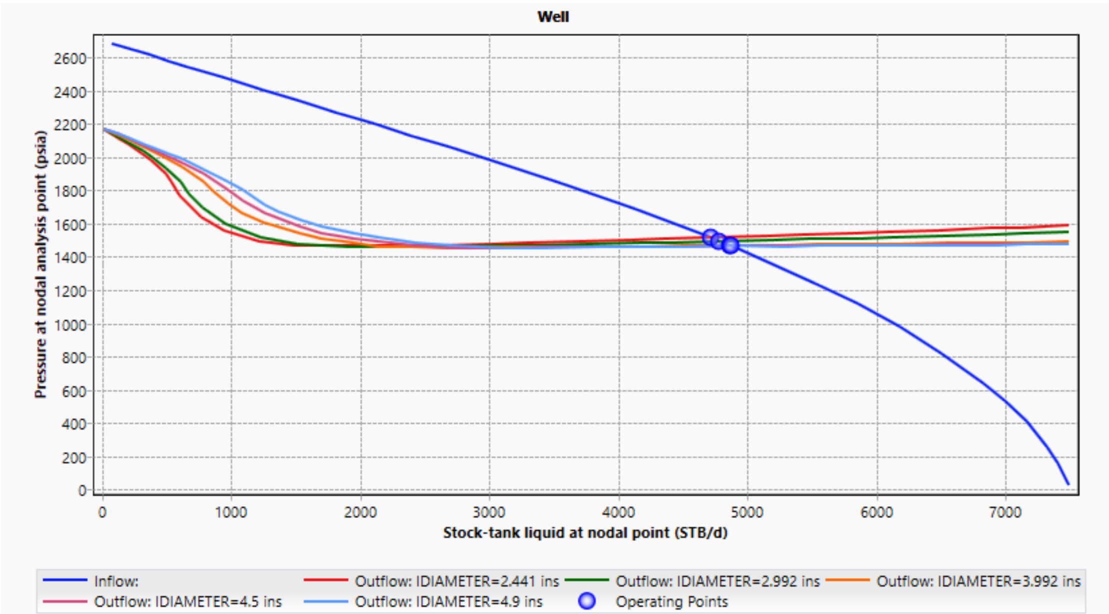

Fig. 8. Well performance curve for cased hole completion with tubing and annular flow.

Figure 10 shows the bottom hole flowing pressure for different tubing sizes for cased hole completion, tubing and annular flow. Results reveals decline in the flowing bottom hole pressure as the tubing size increases. This results from the dual flow path and is more pronounced for tubing sizes of 2.441, 2.992 and 3.992-inches while the bottom hole flowing pressures for tubing sizes of 4.5 and 4.9 inches was constant at 1465.016psia after its initial decline from a value of 1469.155psia from changing the tubing size from 2.441, 2.992 and to 3.992-inches.

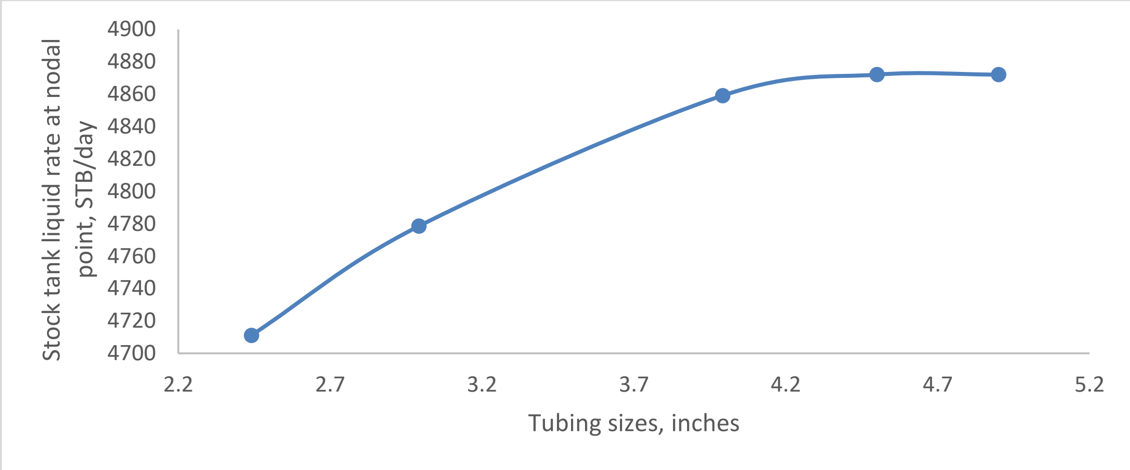

Fig.9. Stock tank liquid rate at nodal point for different tubing sizes for cased hole, tubing and annular flow.

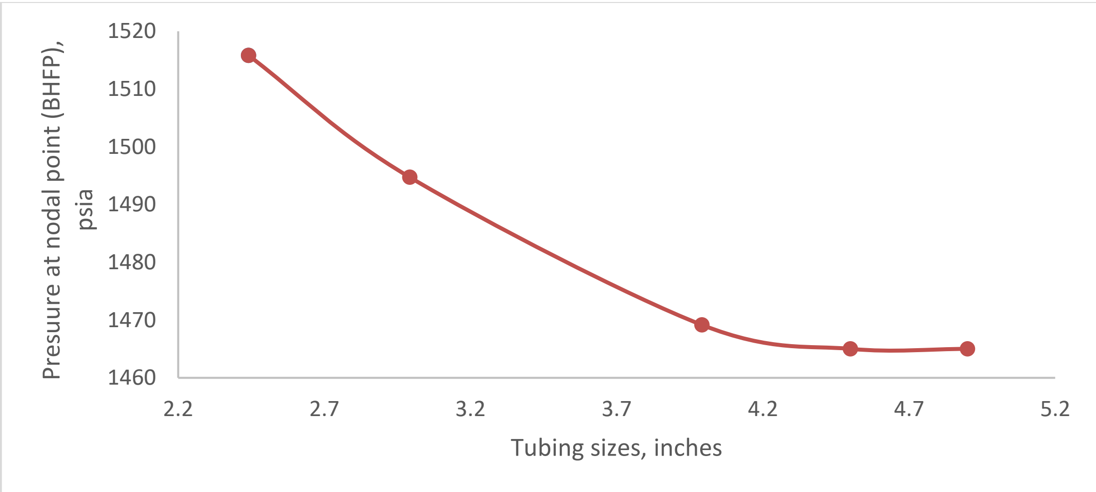

Fig.10. Bottom hole flowing pressure for different tubing sizes for cased hole completion, tubing and annular flow.

3.3 The stock tank liquid rate and bottom hole flowing pressure for cased hole completion, tubing flow and tubing and annular flow

The stock tank liquid rate for different tubing sizes for cased hole completion, tubing flow and tubing with annular flow is presented in Figure 11. There was an increase in the stock tank liquid rate for tubing flow as the tubing size increased from 2.441 to 2.992 and to 3.992-inches but for tubing and annular flow, the stock tank liquid rate was almost the same as the tubing size was increase from 2.441 to 2.992 and to 3.992-inches. For tubing sizes of 4.5 and 4.9-inches, both tubing flow and tubing and annular flow gave almost the same liquid production rate with slight difference between the two flow configurations. For the stock tank liquid rate, when a production tubing size of 2.441-inches was installed in the well, 4711.184STB/day of liquid was produced at nodal point for tubing and annular flow, while for tubing flow, 3305.529 STB/day was produced. This was due to dual flow path which diverted about 1405.655-STB/day through the annulus while allowing 3305.529STB/day for tubing and annular flow which was the production for tubing flow configuration.

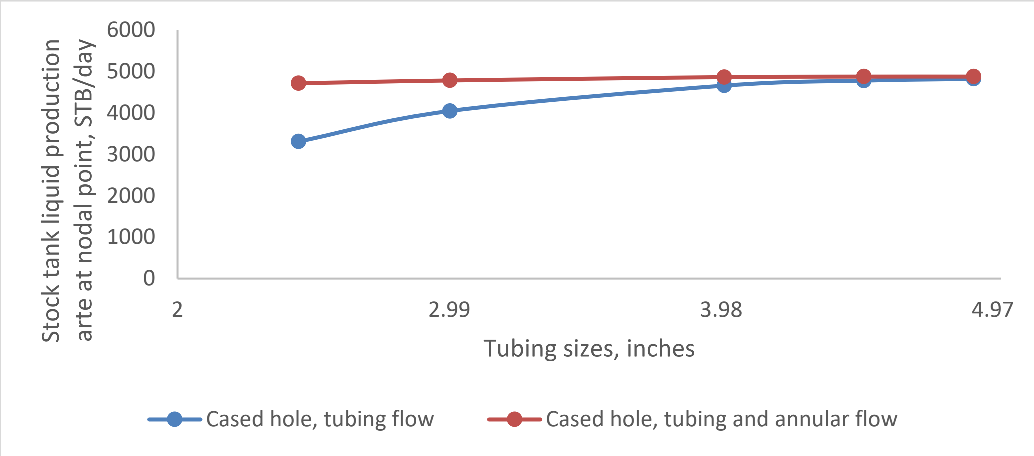

Fig.11.Stock tank liquid rate at nodal point for cased hole completion, tubing and tubing and annular flow.

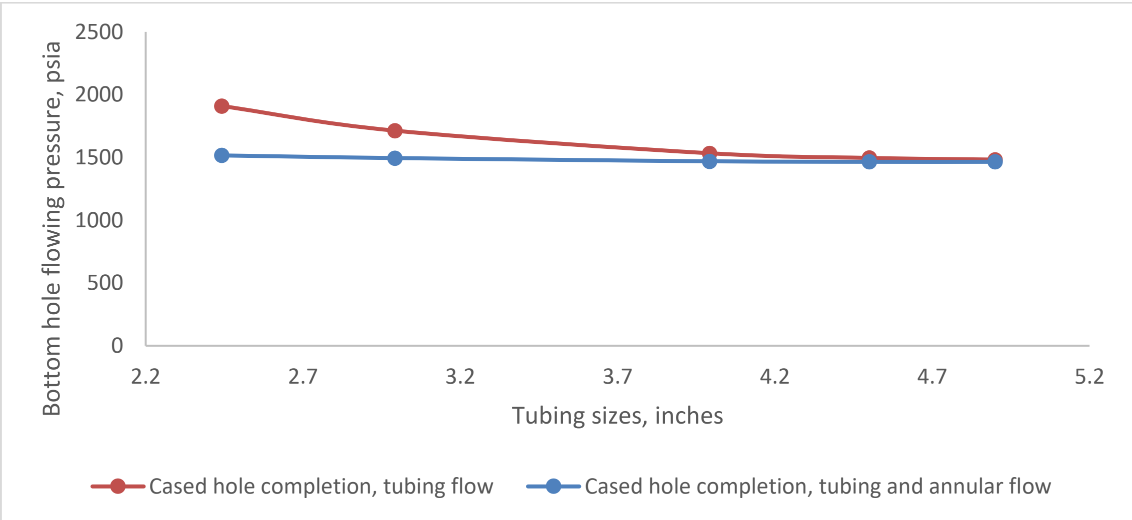

Fig.12.Bottom hole flowing pressure for cased hole completion, tubing flow and tubing and annular flow.

3.4 Effect of tubing size on well performance for liner completion with tubing flow

The well performance curves (IPR and VLP curves) for liner completion, tubing flow for different tubing sizes is shown in Figure 13. There is a downward shift in the intersection between the VLP and IPR curves, which implies an increase in the liquid production rate from the well as the tubing sizes increases. Moreover, the wide separation of the outflow curves for tubing sizes of 2.441, 2.992 and 3.992-

inches shows they yielded different frictional pressure drop. The increase in production rate was due to decrease in frictional pressure losses.

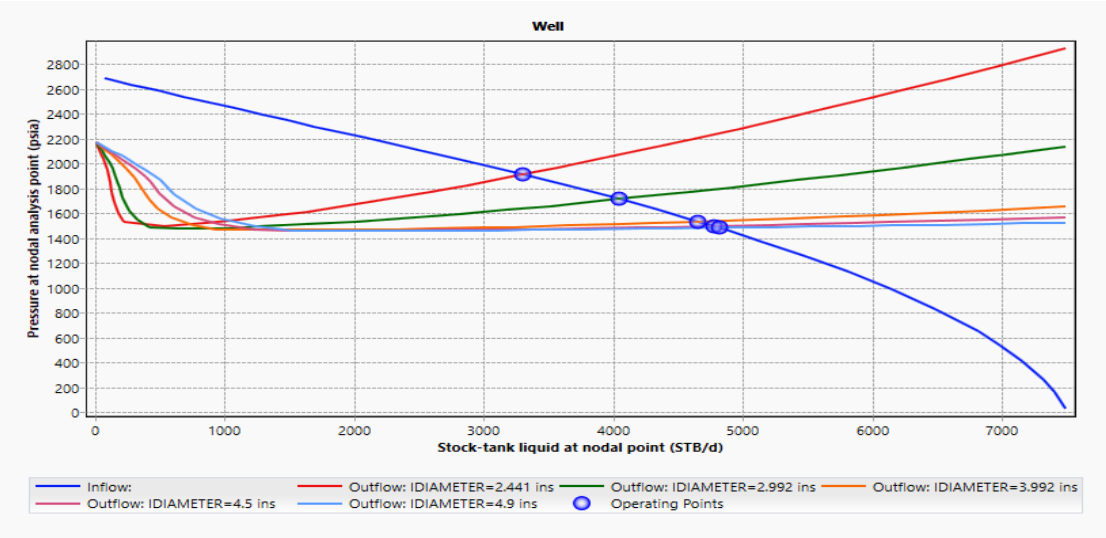

Fig.13. Well performance curve for liner completion with tubing flow.

Figure 14 shows the stock tank liquid rate for different tubing sizes for liner completion with tubing flow. Results reveals an increase in stock tank liquid rate from 3304.84 STB/day to 4040.452STB/day, and 4652.227STB/day for 2.441, 2.992 and 3.992-inches. Increase in tubing size increases the bottom hole flow rate and to an optimum value before declining. The reduction was as a result of pressure drop due to increase in fluid superficial velocity and high flow rate.

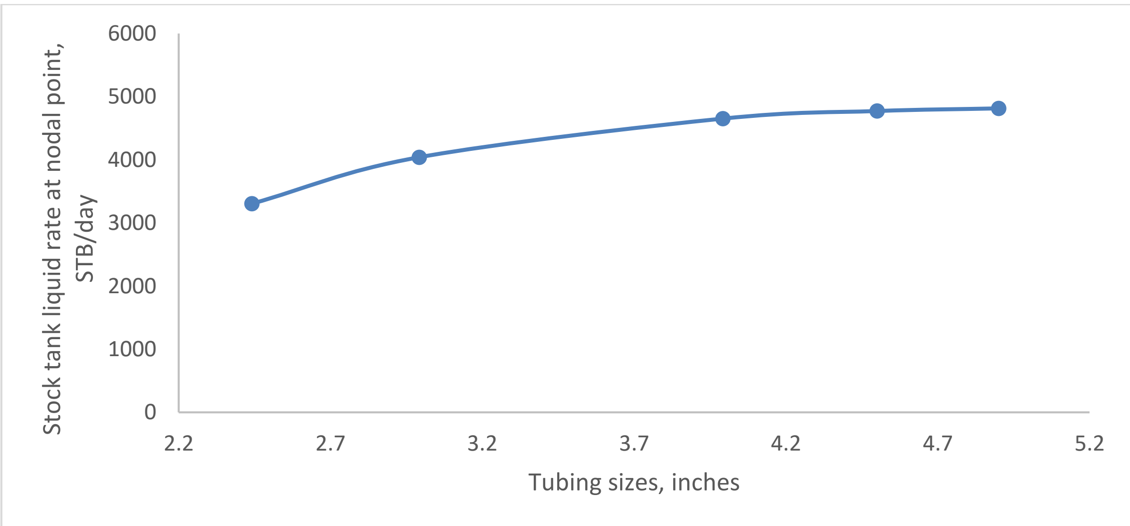

Fig.14. Stock tank liquid rate at nodal point for different tubing sizes for liner completion with tubing flow.

The bottom hole flowing pressure for the tubing sizes for casedhole completion, tubing flow is presented in Figure 15. Result shows a gradual decline in bottom flowing pressure as the tubing sizes increase from 2.441 to 2.992 inches. The decline in the flowing bottom hole pressure results to an increase in pressure drawdown and giving more inflow. Comparing the bottom hole flowing pressure for tubing sizes of 3.992, 4.5 and 4.6 inches, the results indicates a minimal decrease in the flowing bottom hole pressure for the tubing sizes.

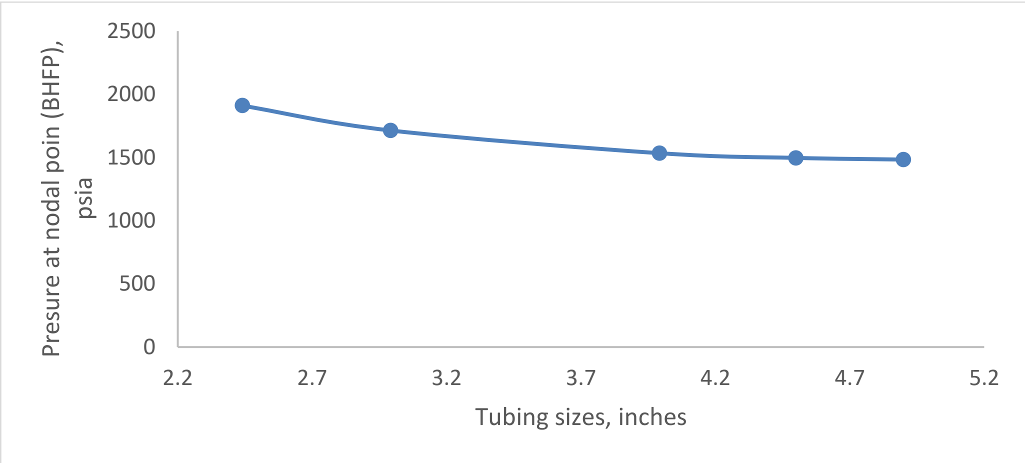

Fig. 15. Bottom hole flowing pressure for different tubing sizes for liner completion, tubing flow.

3.5 Effect of tubing size on well deliverability for liner completion, tubing and annular flow configuration

The well performance curves for different tubing sizes for liner completion, tubing and annular flow is presented in Figure 16. Results reveal a downward shift in the intersection between the vertical lift performance and inflow performance relationship curves as the tubing sizes increases. Also, the closeness of the outflow curves for each of the tubing sizes when compared with liner completion, tubing flow indicates that the tubing sizes do not have much effect on production.

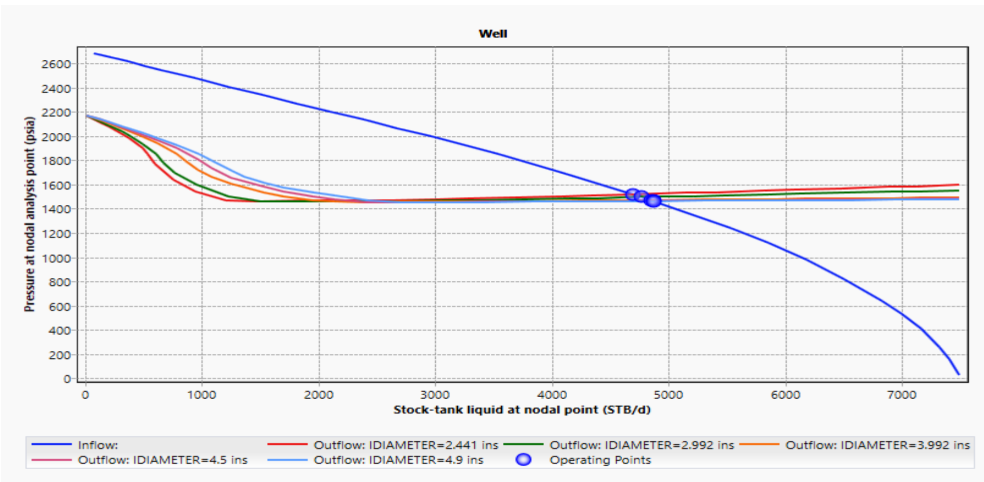

Fig.16. Well performance curve for liner completion, tubing and annular flow.

The stock tank liquid rate at nodal point for the different tubing sizes for liner completion, tubing and annular flow is presented in Figure 17. There was an increase in stock tank liquid rate as the tubing size was change from 2.441 to 2.992 and 3.992 inches.

As the tubing (ID) diameter increases, the pressure drop is reduced and the production rate increased until optimum after which no significant increase in production in rate with respect to tubing size increase. The increase in production rate was as a result of decrease in frictional pressure losses. Here, the gravitational, acceleration and pressure components have little effect on the process. Beyond a certain point, a transition occur which led to decrease in production with tubing diameter. This is attributed to increase in frictional pressure loss due to high flow rate for tubing sizes of 4.5 and 4.9-inches. This agrees with the work of Hernandez Pere, et.al. (2010) on multiphase flow in vertical pipes and shows that larger tubing does not reduce pressure losses.

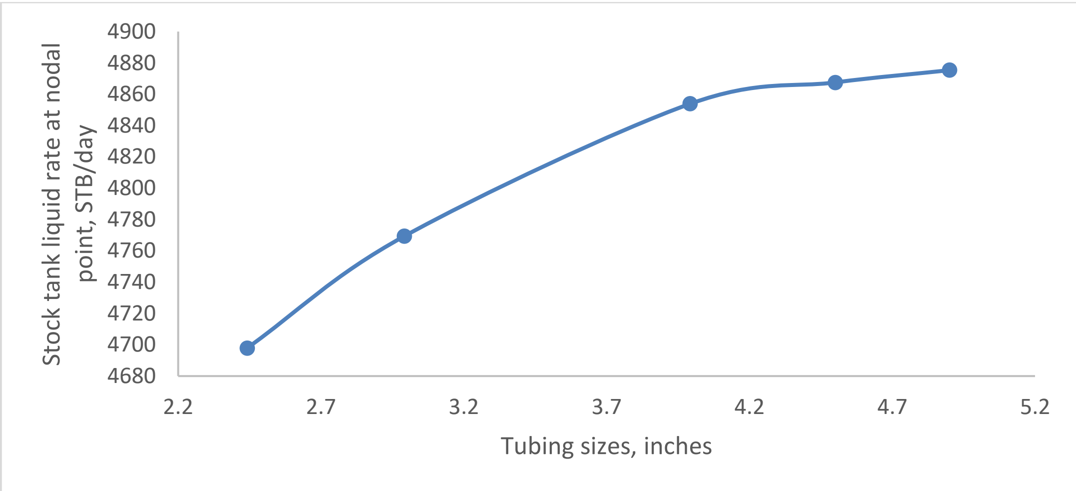

Fig. 17. Stock tank liquid rate at nodal point for different tubing sizes for liner completion, tubing and annular flow.

Figure 18 shows the flowing bottom hole pressure for liner completion tubing and annular flow. There was a decline in the flowing bottom hole pressure as the tubing size increases. This is attributed to the dual flow path and is more pronounced for tubing sizes of 2.441, 2.992 and 3.992-inches. For tubing sizes of 4.5 and 4.9-inches, there was a lesser decline in the flowing bottom hole pressure.

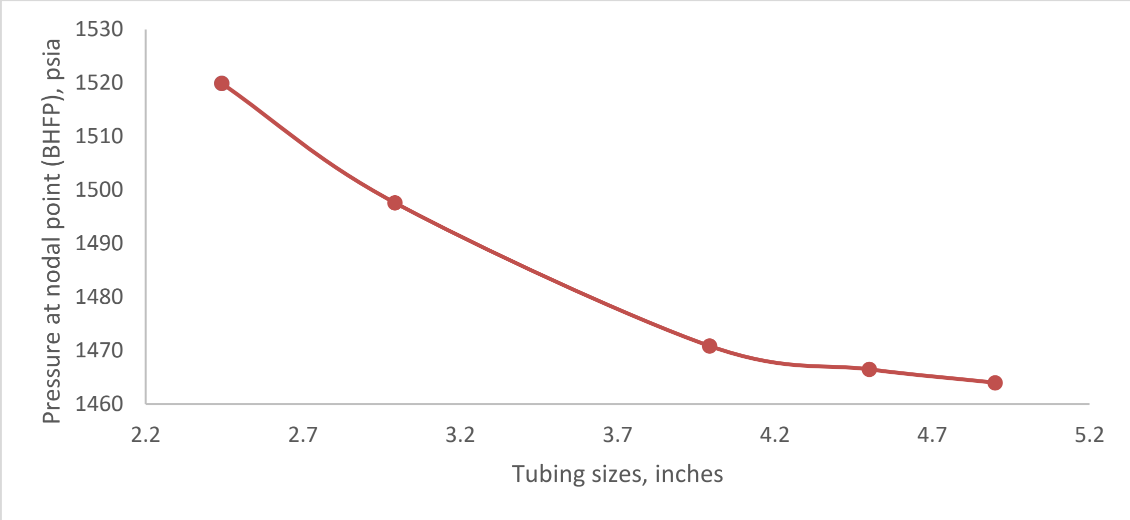

Fig.18: Bottom hole flowing pressure for different tubing sizes for liner completion, tubing and annular flow.

3.6 Stock tank liquid rate and pressure at nodal point for liner completion, tubing flow and tubing and annular flow

The stock tank liquid rate for different tubing sizes for liner completion, tubing flow and tubing and annular flow is presented in Figure 19. Results indicate an increase in the stock tank liquid production rate at nodal point for liner completion, tubing flow as the tubing sizes increases. The stock tank liquid rate increases as the tubing size is increase from 2.441 to 2.992 and 3.992-inches. For tubing and annular flow, the stock tank liquid rate was almost the same as the tubing sizes increases. For tubing sizes of 4.5 and 4.9-inches, both tubing flow and tubing and annular gave almost the same liquid production rate with slight difference. Beyond a certain point, a transition occur which led to decrease in production with tubing sizes. This is attributed to increase in frictional pressure loss due to high flow rate.

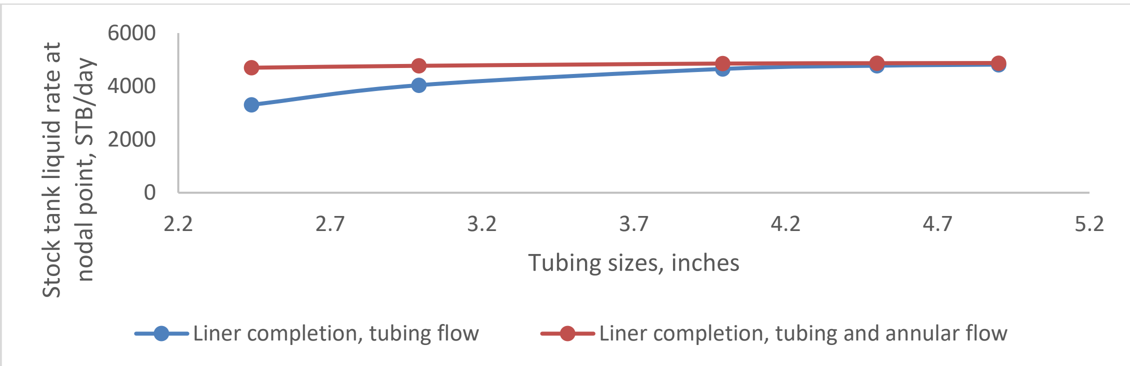

Fig.19. Stock tank liquid rate at nodal point for different tubing sizes for liner completion, tubing flow and tubing and annular flow.

Figure 20 describe the bottom hole flowing pressure for the different tubing sizes for liner completion, tubing flow and tubing and annular flow. The flowing bottom hole pressure was constant for liner completion, tubing and annular flow and was gradually declining for liner completion, tubing flow as the tubing size increased. This was most noticeable for tubing sizes of 2.441, 2.992 and 3.992-inches, but for tubing sizes of 4.5 and 4.9 inches, both liner completion, tubing flow and tubing and annular flow gave almost the same bottom hole flowing pressure. A constant flowing bottom hole pressure for liner completion tubing and annular flow signifies a steady flow of liquid from the well while for tubing flow, the flow of liquid from the wellbore was unstable.

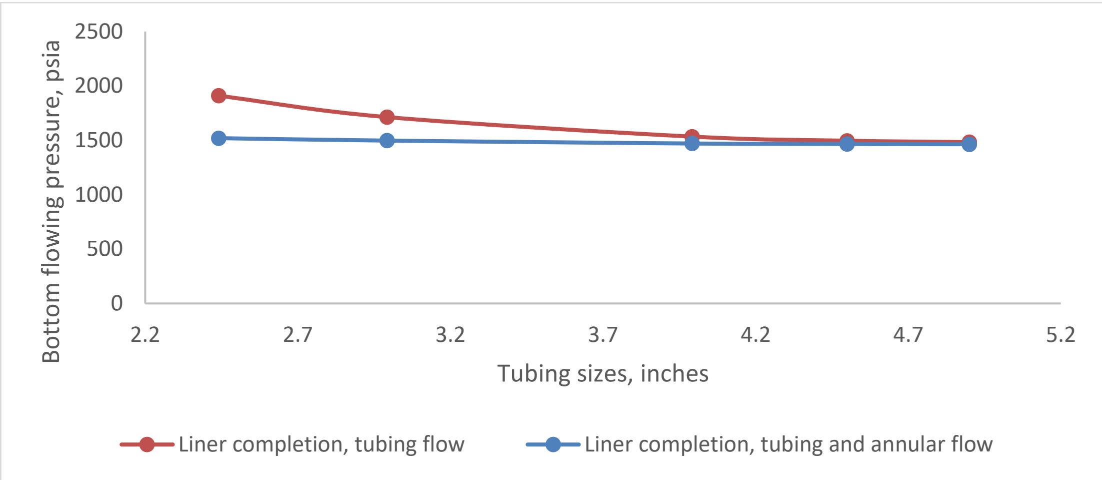

Fig. 20. Bottom hole flowing pressure for different tubing sizes for liner completion, tubing flow and tubing and annular flow.

3.7 Percent increase in production rate for the different flow configuration

The results of the percent increase in production rate for all the completion type and their flow configuration for increase in tubing sizes from 2.441 to 4.9inches is shown in Table 6. Result shows that tubing flow with annular isolation for both completion type have the highest percent increase in production rate.

Table 6. Percent increase in production rate for the different completion type and flow configuration.

Completion and Configuration type	**Percent increase in Production rate**
Cased hole, tubing flow with annular isolation	22.28
Liner completion ,tubing flow with annular isolation	22.26
Cased hole, tubing and annular flow	1.43
Liner completion, tubing and annular flow	1.42

4. Conclusion

In this work, the impact of well completion types and tubing sizes on well performance were studied with the wellbore model design with the PIPESIM™ steady state multiphase flow simulator. The effect of varying the tubing sizes for a given well completion types and flow configurations were analyzed for four scenarios (cased hole completion for tubing flow and tubing with annular flow configuration, Liner completion for tubing flow and tubing with annular flow configuration) with the following conclusions drawn;

i. For a given completion method (cased hole and liner completion), both production mode (flow configuration) and tubing sizes has an effect on the well performance.
ii. A comparison of cased hole and liner completion methods for tubing flow shows a percentage increase in production rate
iii. Cased hole and liner completion methods for tubing and annular flow shows a minimal percentage increase in production rate
iv. Changing the tubing sizes gave optimum well performance for cased hole and liner completion for tubing flow with annular isolation

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