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Nodal Analysis Approach in Minimizing Pressure Losses to Improve Well Productivity

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Abstract

When oil is produced through the tubing, it experiences pressure drop. This pressure loss increases as the oil and gas moves higher in the tubing, this reduction in flowing pressure will cause more dissolved gas to come out of solution. Consequently, the flow stream, especially free gas, expands in volume per unit flow rate. The loss in pressure between the reservoir and the surface facilities leads to the reduction in the volume of oil that can be produced from the initial oil in place. Pressure loss in the production system has been a huge challenge in the transportation of reservoir fluids to the surface. This has attracted different investigative approach to study how to reduce pressure loss in the production system, which is vital to the volume of reservoir fluids produced at the surface. Previous research has shown that increasing the tubing internal diameter (ID) size gradually as we move from bottom to top gives allowance for expansion and ultimately improves performance of the tubing system. This increased performance is due to a lower amount of pressure losses on the walls of the larger ID tubing placed above. PIPESIM was applied to study how a well productivity can be improved by using tapered internal diameter completion, how duplex tubing can influence well production, i.e. a combination of only two strings. Nodal analysis was performed on a case study well to ascertain this fact, and sensitivity analysis on increasing gas oil ratio (GOR) and water cut was also carried out. This research study also focused on the estimation of the optimum length of a duplex string (i.e. two tubing strings with the larger internal diameter (ID) placed above). The results of this research reveal that higher flow rates are possible using an optimal length combination of a duplex string, which are better than the flow rates from the conventional single tubing and the pressure loss experienced is relatively lower when compared with single tubing strings.

Keywords: mathematical knowledge management, emerging trends, strategies, information resources, matrices, eigenvalues

INTRODUCTION

Any production well is drilled and completed to move the oil and gas from its original location in the reservoir to the stock tank or sales line. Movement of these fluids requires energy to overcome friction losses in the system and to lift the reservoir products to the surface. The fluids must travel through the reservoir and the piping system and ultimately flow into the separator for gas-liquid separation. Fluid movement through these various sessions of the reservoir production system results to pressure losses or energy reduction. Principally, pressure losses in the tubing are due to three factors; namely, Friction component, elevation change component and acceleration component.

These components have different effects on the pressure loss in the tubing system with the effect of the friction component being the most influential in a two phase flow system. The elevation change component has a considerable effect on the system as it depends on the density of the fluids in question and liquid hold up.

Of all the three factors, the acceleration component is usually ignored. When it is considered, various assumptions are made regarding the relative magnitudes of parameters involved to arrive at some simplified procedure to determine the pressure loss due to this component.

Conventional tubing string design entails selecting a constant internal diameter for all the tubing sections from bottom to top. The upper sections of the string, however, have a greater wall thickness to support the load of the string below. Thus conventional tubing strings are tapered in terms of outer diameter, which is necessitated by mechanical loading requirements. Previous research has shown that increasing the tubing internal diameter (ID) size gradually as we move from bottom to top gives allowance for expansion and ultimately improves performance of the tubing system. This increased performance is due to a lower amount of pressure losses on the walls of the larger ID tubing placed above.

The flow of hydrocarbons from reservoir conditions, into the vertical lift section of the production system and to the gathering facilities, experience reduction in energy due to pressure losses. Pressure loss in the production system has been a huge challenge in the transportation of reservoir fluids to the surface. This has attracted different investigative approach to study how to reduce pressure loss in the production system, which is vital to the volume of reservoir fluids produced at the surface. The theory of Nodal analysis and PIPESIM application was used to study the concept of tapered strings and duplex tubing combinational strings to improving on the well productivity. The findings from this research will encourage its application in the oil and gas production industry, in turn leading to higher recoverable hydrocarbons.

LITERATURE REVIEW

The idea of tapered internal diameter completion (TIDC) is not entirely new, as can be seen in the definition of tapered string for production that exists in the literature: A tapered production string may be configured with larger OD tubing joints in the upper wellbore area to optimize the hydraulic performance of the string. Although a tapered coiled tubing string will have the same tubing outside diameter throughout, the upper portion of the string may have a greater wall thickness to support the load of the string below. (Schlumberger oilfield glossary).

However, an extensive search of published literature has revealed few applications of the tapered ID string concept for optimizing production. Trenchard & Whisenant (1935) reported probably the earliest case of tapered tubing string completion, which was necessitated by well flow back problems that occurred after shut-in. conventional methods to a well flow back in such cases included: pumping, flowing with the aid of valves, and tapered tubing. The tubing string method was found to be quite satisfactory. It usually consisted of a string of pipe, half of which is $^3/_4$–inch, and the other half, 1-inch. The use of tapered tubing afforded a more continuous flow and probably a smaller amount of injected gas at the start. Golan and Whitson (1986) reported the use of a smaller size (ID) of tubing in the liner section of the well. In this case, the smaller tubing size (OD, $2^7/_8$) was necessitated following casing collapse above the pay zone. The collapsed section was repaired by placing a liner inside it. The smaller tubing size was connected to the existing upper tubing ($3^1/_2$-in.) section via a crossover (Fig. 1.1)

Schlumberger reported using a tapered tubing string of 5.5 to 7 in. in a condensate well with a high gas oil ratio (GOR). The well was producing 5500 BOPD with a gas /oil ratio of 9600 SCF/STB through a mono tubing completion consisting of a 7-in. liner. In order to avoid liquid loading, a tapered tubing string of 5.5 and 7 in. was used, which caused a fluid velocity increase in excess of the critical velocity of 8 m/s at a flowing wellhead pressure of 1430 psi.

The most recent case of tapered –string tubing is reported by Tibbles et al (2004). The well was producing at 2147 BOPD before hydraulic fracturing was considered. Pre-fracturing nodal analysis indicated a high AOFP using the designed hydraulic fracturing parameters. In order to lift the increased volumetric throughput, a larger ID tubing string was needed. A tapered tubing string ($4^1/_2$-in. tubing from surface to 5000-ft. and $3^1/_2$-in. tubing from 5000-ft. to 5892-ft.) string indicated a production rise to 3145 BOPD. After fracturing, the measured flow rate was 3101 BOPD.

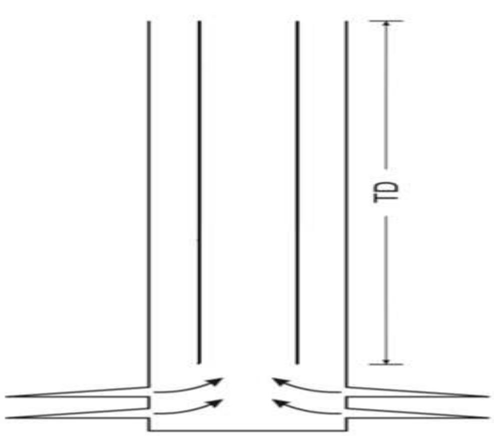

Fig.1 Conventional Tubing Completion

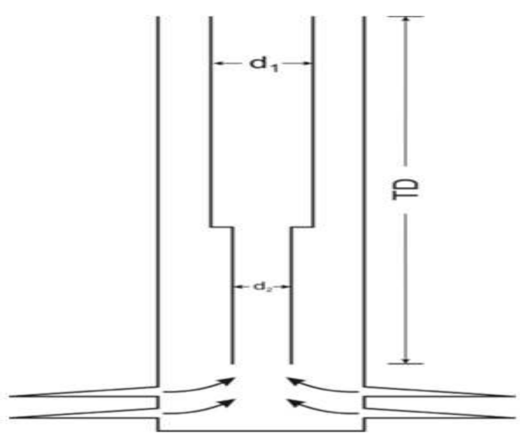

Fig.2 Dual Completion Tapered Tubing

Inflow Performance Relationship

Over the years so many models have been developed for estimating the reservoir deliverability. It is generally used to estimate various operating conditions such as determining the optimum production scheme and designing production equipment of a particular well. The most common and broadly used IPR equation is the productivity index or straight-line IPR. The assumption used is that the flow rate is proportional to the pressure drawdown in the reservoir. IPR is used to describe reservoir deliverability. However, it is not enough for a production engineer to comprehend wellbore flow performance to recommend oil well equipment and optimize well production situation.

Vogel (1968) with the help of a computer model constructed IPRs for a number of suppositional saturated oil reservoirs which were under a wide range of conditions. This method not only helps to regularize IPR but also generates IPR without any physical units.

Wiggin (1993) derived equations to calculate inflow performance using four sets of relative permeability and fluid property input data for a computer model. The assumption used for this method is that the initial reservoir pressure is at its bubble pressure.

Standing (1970) rearranged Vogel's equation to calculate future inflow performance relationship of a well as a function of reservoir pressure.

Tubing Performance Relationship
According to Beggs (1991) tubing performance relationship (TPR) is the relationship between bottom hole pressure and the flow rate. TPR is used to observe the connection between the total tubing pressure drop and a surface flowing pressure value as a function of flow rate, GOR (GLR), tubing ID, density, surface pressure, and average temperature.
A well deliverability is mostly dependent of the pressure drop required to raise a fluid through the production tubing at a certain flow rate. The tubing pressure drop is the sum of the surface pressure, the hydrostatic pressure of the fluid, and the frictional pressure loss due to the flow.

As stated earlier, the IPR is not enough for a production engineer to comprehend wellbore flow performance and to recommend oil well equipment and optimize well production situation. TPR and IPR intersection is used to find the stabilized flow rate and the corresponding bottom hole pressure which consequently allows a full understanding of the wellbore flow performance to recommend oil well equipment and optimize well production situation.

RESEARCH METHODS
This research uses both a descriptive and analytical approach. The software being used for analysis in this research is PIPESIM, also applied is the theory of Nodal Analysis. The limitations inherent in this methods of approach also influenced the findings, not forgetting that this study is on tapered strings and duplex tubing strings. The approach can be tested with the trio and quad completion configurations. This paper focused on how a well productivity can be improved by using tapered internal diameter completion, it also ascertains how duplex tubing can influence well production, i.e. a combination of only two strings. This paper also estimate the optimum length of a duplex combination and the results will shows that duplex strings produces better flow rates than conventional single tubing .

Analysis will be conducted on a model well considering increasing water cut (WC) and gas oil ratio (GOR) which will be based on different scenarios comparing different tubing combination.

These different scenarios below will be used while conducting analysis.
Scenario 1:
Single tubing 1.995, 2.441, 2.992, and 3.340 in. tubing sizes used.
Scenario 2:
Dual tubing
Three different sub-scenarios with different tubing inside diameter sizes, 1.995, 2.441, 2.992 and 3.340 in., were conducted and their design will be as follows

- d_1 = 2.441 in. and d_2 = 1.995 in.
- d_1 = 2.992 in. and d_2 = 2.441 in.
- d_1 = 3.340 in. and d_2 = 2.992 in.

Data Acquisition
The type of data used in this research is strictly secondary. This was selected in preference to actual field data so that a wider range of sensitivity analysis can be conducted on this data and the data was selected from Beggs (1991)

The most important concern for the choice of the typical production test data is to be capable to run a simulation and obtain the producing capacity of the well using different scenarios. To accomplish this, the following data inputs were used.

S/N	PARAMETER	VALUES
1	Avg. Reservoir Pressure, psig	3482
2	Bubble Point Pressure, psig	3600
3	Flowing Wellhead Pressure, psig	400
4	Well Depth, ft.	10000
5	Oil Density, °API	35
6	Gas Gravity (air 1.00)	0.65
7	Water–Cut, %	50
8	GLR, scf/stb	400
9	Reservoir Temperature, °F	180
10	Liquid Flow Rate, stb/day	320

Production Optimization
TPR and IPR intersection was used to find the stabilized flow rate and the corresponding bottom hole pressure. Stabilized flow rate is achieved when there is a continuous flow between the reservoir and the tubing string. In order to achieve this, the method

of nodal analysis was employed and the bottom hole (point 6) selected as the nodal point as shown in fig.3

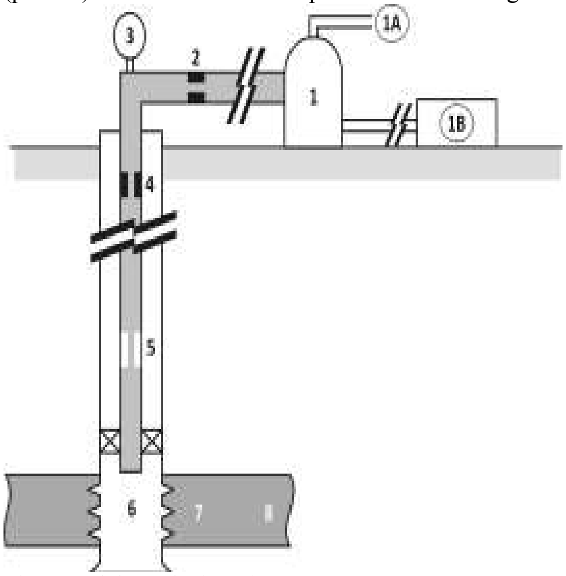

Fig 3 Nodal Analysis Point

The empirical method used in this study to generate IPR is the Vogel's method, and the empirical method used to generate TPR is Hagedorn & Brown correlation. Both methods are incorporated in the following software used, PIPESIM®.

Vogel's method for IPR generation

$$\frac{q_o}{q_{o(max)}} = 1 - 0.2\frac{P_{wf}}{P_R} - 0.8\left(\frac{P_{wf}}{P_R}\right)^2 \quad (1)$$

Hagedorn & Brown correlation for TPR generation

$$\frac{dp}{dz} = \frac{g}{g_c}\bar{\rho} + \frac{2f\bar{\rho}u_m^2}{g_c D} + \bar{\rho}\frac{\Delta(u_m^2/2g_c)}{\Delta z} \quad (2)$$

Expressed in oil field units as

$$144\frac{dp}{dz} = \bar{\rho} + \frac{f m^2}{(7.413\times10^{10}D^5)\bar{\rho}} + \bar{\rho}\frac{\Delta(u_m^2/2g_c)}{\Delta z} \quad (3)$$

ANALYSIS OF RESULTS

PIPESIM was used to simulate different tubing sizes configurations and the results are as follows

Conventional Tubing Results

Case 1: tubing size of 1.995 in.

The nodal analysis plot for this tubing size is shown in figure 4

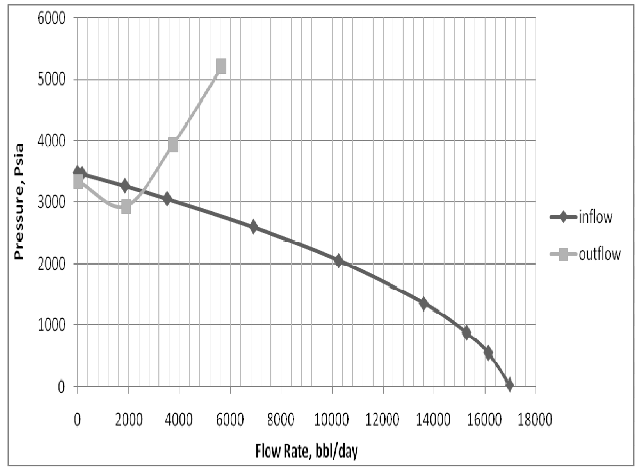

Fig. 4 Nodal Analysis of 1.995 in. tubing

Table 2. Optimum Flow Rate and Pressure

Reservoir pressure(Pisa)	Flow rate (bbl./day)	Pressure (Pisa)
3840	2380	3200

Case 2: tubing size of 2.441 in.

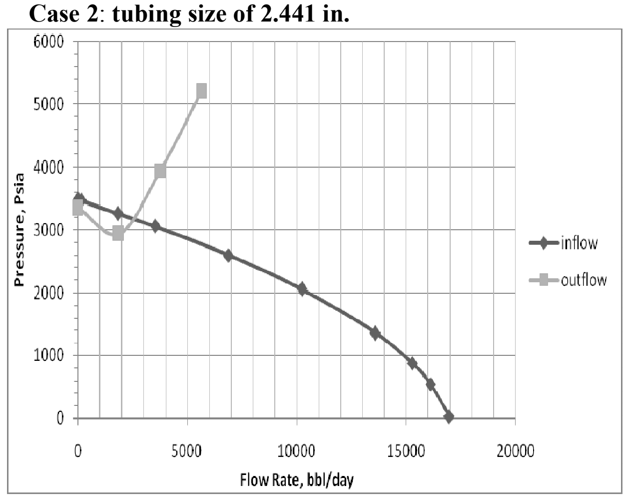

Fig.5 Nodal Analysis of 2.441 in. tubing

Table 3. Optimum Flow Rate and Pressure

Reservoir pressure(Pisa)	Flow rate (bbl./day)	Pressure (Pisa)
3840	2878	3120

Case 2: **tubing size of 2.992 in.**

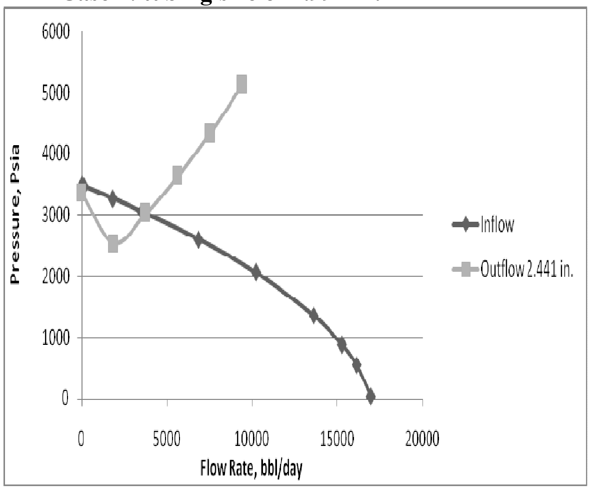

Fig.6 Nodal Analysis of 2.992 in. tubing

Table 4. Optimum Flow Rate and Pressure

Reservoir pressure(Pisa)	Flow rate (bbl./day)	Pressure (Pisa)
3840	3769	3026

Case 4: tubing size of 3.340 in.

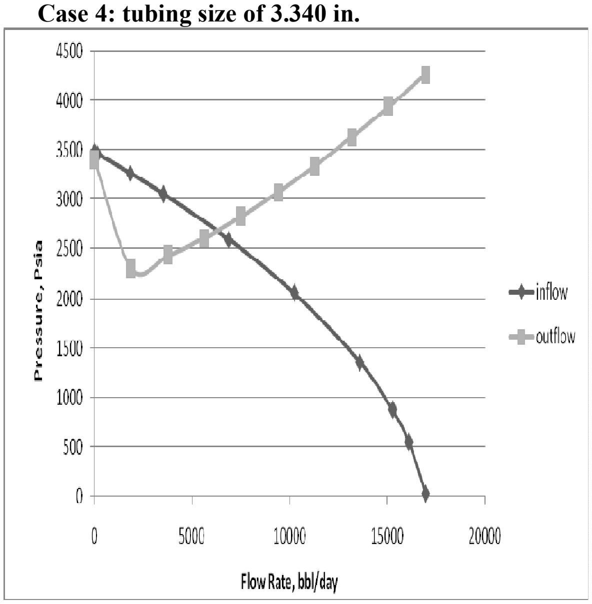

Fig.7 Nodal Analysis of 3.340 in. tubing

Table 5. Optimum Flow Rate and Pressure

Reservoir pressure(Pisa)	Flow rate (bbl./day)	Pressure (Pisa)
3840	6291	2684

Now these tubing sizes shall be simulated in a dual combination string. First, we shall consider a combination of 1.995 and 2.441 in the ratio of 0.5 i.e. 5000 ft. each. The results of the nodal analysis is as shown in the figure below (fig 8)

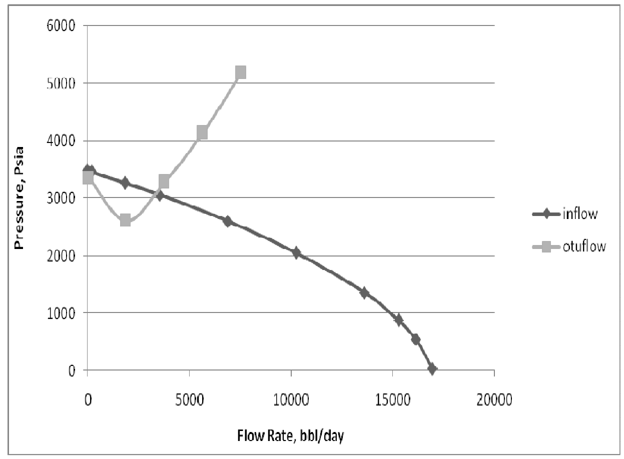

Fig.8 Nodal Analysis of 1.995 and 2.441 in. tubing

Table 6. Optimum Flow Rate for Duplex and Single Strings

Reservoir pressure (Pisa)	Flow rate 1.995/2.441 in. (bbl./day)	Flow Rate 1.995 in. (bbl./day)
3840	6291	2684

It is seen from table 4.5 that the flow rate for a combination of 1.995 and 2.441 in. tubing is higher than that of 1.995 in. alone. This can also be shown by a combination of 2.441/2.992 and 2.992/3.340 and this will be shown in figures 4.7 and 4.8 respectively.

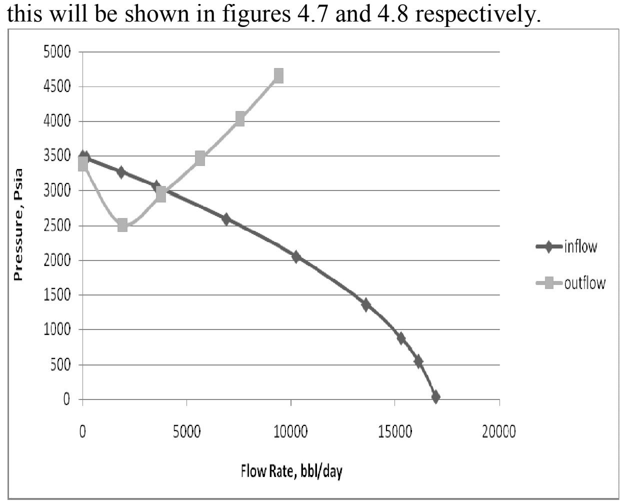

Fig. 9 Nodal Analysis of 2.441 and 2.992 in. tubing

Fig.9 shows the inflow outflow curve for a combination of 2.441 and 2.992 in. tubing. It is seen that the optimum flow rate of this combination is better than that of the single 2.441 in. completion. This is also depicted according to table 4.6 as compared to table 4.2

Table7. Optimum Flow Rate for Duplex and Single Strings

Reservoir pressure (Pisa)	Flow rate 2.441/2.992 in. (bbl./day)	Flow Rate 2.441 in. (bbl./day)
3840	4831	2878

Also, fig.10 shows the combination of a 2.992 and 3.340 in. tubing and its optimal flow rate was compared to that of a single configuration of 2.992 in.

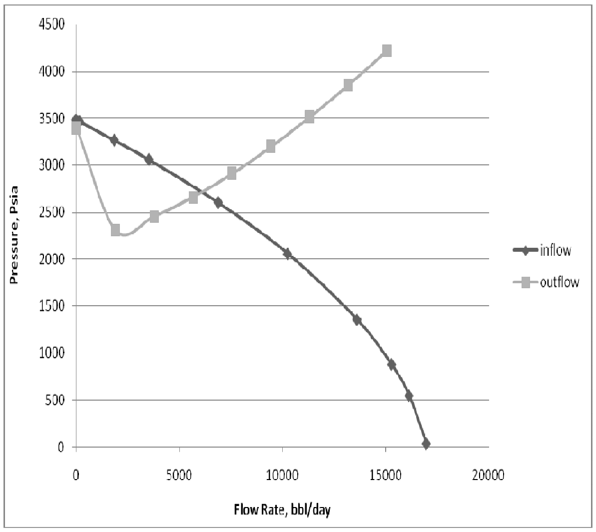

Fig.10 Nodal Analysis of 2.992 and 3.340 in. tubing

Table 8. Optimum Flow Rate for Duplex and Single Strings

Reservoir pressure (Pisa)	Flow rate 2.992/3.340 in. (bbl./day)	Flow Rate 2.992 in. (bbl./day)
3840	4831	3769

Length Optimization

Next, we shall optimize the combination of a 1.995 in. and 2.441 in. with respect to the lengths of the upper and lower sections. In order to do this, we shall make a plot of the flow rates of different length of the upper section (2.441) starting from 5000ft. **table 9** shows this data relationship.

Table 9. Flow Rate and Well Length of the Upper Section.

Flow rate (bbl/day)	Length of Upper Section (ft.)
3246	5000
3417	6000
3557	7000
2376	8000
2365	9000

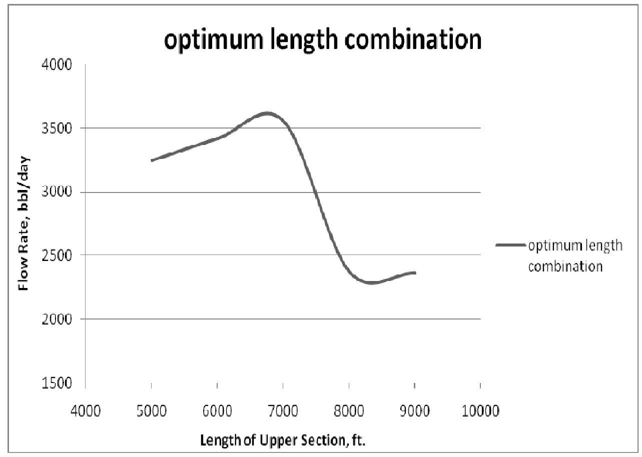

Fig.11 Optimum Length Combination of 1.995/2.441 in.

DISCUSSION OF RESULTS

The results presented in this paper suggest that the TTWC is a potent way of optimizing production. Figures 4 – 7 show nodal analysis plots of 1.995, 2.441, 2.992, and 3.340 tubings respectively. It was noticed that the optimal flowrates increase as we increase tubing size. As seen from fig.11 the optimal length of the upper section of this combination is 7000ft and the lower section should run from 7000-10000ft. Any length longer than 7000ft. will only cause the well to load because of the pressure loss due to elevation since the upper section will be exerting a force on the lower section.

Figure 8 then combines a 1.995 and 2.441 in equal length ratios and the flow rate obtained is tabulated in table 7. It is seen that the flowrate of this duplex combination exceeds that of a single completion using 1.995 in. shown in table 2.

Figure 9 also attempts to achieve the same result as figure 8 but in this case, a duplex combination of 2.441 and 2.992 in. the results from table 8 also show an increase in flowrate as we move from the single 2.441 in. to the duplex string. The major finding from these results presented is that the duplex string produces with a better flowrate than that of single tubing.

Figure 11 shows the results of optimizing the length of a duplex 1.995 and 2.441 combination string. As seen from the graph, better flowrates are noticed as we increase the length of the upper section and then drops when 7000ft. is used in the upper section. The implication of this is that the optimal length of the upper section of this combination is 7000ft and the lower section should run from 7000-10000ft. Any length longer than 7000 ft. will only cause the well to load because of the pressure loss due to elevation since the upper section will be exerting a force on the lower section.

CONCLUSION

The research has revealed that increasing the tubing size gradually as we go up the production string affects flowrate and pressure. It was also obvious from the results that increasing the tubing ID reduces pressure losses due to friction. However, care must be taken as to determining the respective lengths of the upper and lower sections so as to achieve optimal production.

The combination string of 1.995 in. and 2.441 in. the flowrates gradually increased as we increased the length of the upper section of the tubing and then declined as we increased the length of the upper section to 8000ft. this was as a result of increasing the pressure loss due to elevation. This further suggest that there is an optimum point at which these pressure losses are balanced and this was determined to be at 7000ft. for the upper section of 2.441 in. and the remaining 3000ft. is run with 1.995 in. tubing.

This method can also be applied to trio and quad completion configurations as proposed by Affanaamambo B. O. (2008).

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