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Investigating Effects of Tubing Sizes on Hydrocarbon Recovery in Niger Delta

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Abstract: This research employed a qualitative system of analysis that incorporates both nodal and economic analysis of distinct tubing sizes, their flow rates and pressure sensitivity, using tubing performance and four distinct economic profitability indicators. Furthermore, the four-profitability indicators were subjected to a cause factor sensitivity test. Results of the nodal analysis and tubing size sensitivity showed increasing flow rates with increasing tubing size from 1.90-inch tubing size to 4.275-inch and plateaued with highest flow rates within the ranges of 4.75-inch to 5.70-inch and then declined in ranges greater than 6.0-inch. while pressure sensitivity showed relative pressure decrease with increasing tubing size showing lowest pressure points within 4.75-inch to 5.70-inch tubing sizes and then increased in ranges greater than 6.0-inch. Economic profitability analysis was carried out on the tubing sizes using CAPEX, tubing cost and oil production rate through four profitability indicators which includes; NPV, IRR, PI and PP. The outcome of the analysis aided the determination of an optimal tubing size of 5.225-inch ranking it highest in all four utilized profitability tools amongst all four analyzed tubing sizes.

Keywords: Tubing Sizes, Pressure, Economic Analysis, Profitability, Discount Rate

1. Introduction

The oil and gas industry is a vase industry that requires extensive capital to develop, it cuts across several phases of processing ranging from exploration, through to completion and development. Each of these phases encompass several oil and gas operations, some of which simultaneously intercept throughout all phases. Every phase of the operation, is just as important as the order holding the capacity to make or mar the overall process. This implies that in cases where operations have progressed to development and production stage, it's still not a time to be at ease noting that irrespective of how far operations have gone, any simple error or operational malfunction can still mar the operation. Hence, proper reviews and evaluations on development and production parameters is carried out extensively. One of the most important determinant parameters, which have been described according to [12] as having the capacity to kill the well is tubing utility. Tubing utility encompass both size, material strength and installation of production tubing. Tubing utility doesn't only have the capacity to kill well, but it also has the capacity to compromise production rate as well as incurring additional cost and by extension minimizing economic benefit. Oil and gas production systems must be built in such a way that it doesn't compromise reservoir pressure while maximizing production, and thus ensuring in place well control.

Oil and gas production systems, designed to move hydrocarbons from their position at the reservoir to their desired destination at the surface/stock tank are made up of components which play individual roles to ensure an effective hydrocarbon recovery. Tubing again, has been described as a component in the production system of a flowing well and is the main channel for oil and gas production [13]. After well completion, the reservoir fluid could be produced through the casing, tubing or both. Mostly wells are produced through the tubing in order to isolate the casing from corrosion and for use of artificial lift systems, [6, 4]. It became essential that for any selected production tubing size, the well should flow naturally. Choosing an undersized tubing will result in excessive flow velocity and hence increased friction resistance in the well which limits the well production rate. The undersized tubing may as well restrict the type and size of artificial lift equipment [2]. Using oversized tubing on the other hand would result in low flow velocity and hence excessive liquid loss due to gas slippage effect. Large tubing size would also complicate workover operations due to loading of the well resulting from heading and unstable flow [2]. [11], emphasized the need to select the optimum tubing size that ensures an optimum state for the friction resistance and liquid-phase loss due to flowing time lowest lifting energy consumption.

Optimum tubing selection is commonly done by using nodal analysis to perform sensitivity analysis on the various tubing sizes during the flowing production period of the well [11]. The system analysis that combines the inflow performance relationship (IPR) and the tubing performance relationship (TPR) curves so as to obtain the operating flow rate and pressure at a specified node is called nodal analysis [3]. Establishing and a relationship between pressure drop and flow rate performance in a reservoir is paramount for production optimization [1] because it will help to; possibly forecast well production with the knowledge of Nodal analysis; forecast production rate, cumulate production for oil and gas wells, obtain information of oil and gas production costs; making it possible to use the results for production prediction and field economic analysis [5]. Hence developing a relationship between the inflow and tubing performance curve with respect to tubing size is a critical means of determining the optimum production rate for hydrocarbon recovery.

2. Literature Review

Tubing size determination in relation to its production capacity, is a vital part of the well development phase in the industry. It poses strong influence in determining the success or failure of the overall process and most essentially the production yield which consequently, affect the economic profitability of the overall process. Conventionally in the industry, a well completion evaluation is carried out by production engineers, in order to develop well completion design with optimal production. The result of this practice is that the well production is limited to the degree to which the well completion design allows. Thus, it is on this basis, that certain production variables are evaluated in terms of their effects on production. After a well completion operation is completed, the tubing size and mode of production is then determined based on already established well completion parameters. Tubing is an essential part of the production system; it forms the most important path way for the development of an oil and gas field [13].

Again, [13] in his book further described the full weight consequence of tubing determination and application in production operation, he reported that bottom hole to surface pressure drops initiated by fluid lifting may range up to 80% of the overall reservoir pressure. Therefore, stressing the need for the determination and application of optimal tubing size unique to a particular oil and gas well as the case may be. Optimal tubing applications allows for best well control practice, which in turn sustains well longevity and enhances results of workovers [7].

An efficient operation in the oil and gas industries requires the knowledge of tubing performance of flowing wells, and the future performance of the wells may also be evaluated, [9]. He further stated that the flowing bottom hole pressure of a well varies with the production rates for a given well head pressure, hence plotting these parameters against each other on a Cartesian coordinate will yield a curve called the tubing performance curve (TPC).

In their book, [7] also noted that the determination and installation of tubing is a critical phase that is capable of killing the well and curing additional cost. Thus, tubing must be designed in such a way that it meets all stress and load condition exerted by the well in course of its operational routine practices such as, tension, burst and collapse. Their report further highlighted that production tubing's installed with packers, provide sufficient casing isolation that prevents it from interacting with well fluids and thus, prevents casing corrosion problems.

In their works, [8] used C# programming language to develop software for optimizing tubing and production case sizes for flowing oil and gas wells. It was shown that their software could produce the accurate results for tubing and production case sizes for flowing oil and gas wells but does not consider the future IPR and therefore impossible to predict when the selected optimum tubing size will stop flowing.

3. Methodology

This research work was done using Schlumberger's [10] and Oracle's CRYSTAL BALL. PIPESIM was used to model the well by properly inputting the well parameters such as casing depths, tubing, downhole equipment such as packer etc.

Schlumberger's PIPESIM (2017) was also used to carry out nodal analysis and sensitivity analysis of different tubing sizes while CRYSTAL BALL was used for Monte Carlo simulation to carry out economics analysis of the different tubing sizes.

Prediction of discounted cash outflow and inflow over the projected field life was carried out using an excel spreadsheet. Parameters such as the Capital Expenditures (CAPEX), operating expenditure (OPEX), anticipated revenue, marginal field fiscal arrangements, oil price forecast and the desired discount rate were used to estimate the NPV, Profitability Index (PI), Payout Period (PP) and internal Rate of Return (IRR). For well XYZ, some assumptions were made which includes:

a) Price of crude oil was assumed as $59 (the average price between 2018-2020);
b) Royalty at 12.5%;
c) Discount rate was at 15%;
d) Tax at 30%;
e) For a specific period of 10 years.

Input data for well XYZ

Table 1. *Wellbore data for well XYZ.*

Type	From MD (ft)	To MD (ft)	ID (in)	Wall Thickness	Roughness
Conductor casing	0	1500	20	0.99	0.001
Surface casing	0	3000	16	0.8	0.001
Intermediate casing	0	6000	12	0.6	0.001
Production casing	0	10000	8	0.55	0.001
Liner	7999	10000	6	0.45	0.001
Tubing	0	9500	2	0.35	0.001

Table 2. *PVT and Production Test Data for Well A.*

Type	Value
Reservoir Pressure, Psia	4000
Wellhead Pressure, Psia	500
Reservoir Temperature, F	200
IPR Basic	Liquid
AOFP, stb/day	1200
IPR model	Vogel
Water cut, %	20
GOR, scf/stb	1500
Gas specific gravity	0.7
Water specific gravity	1
AP1	40 API
Fluid	Light oil + gas

4. Results and Discussions

After the data was correctly inputted, the software was allowed to run and thus, generating well model for well XYZ shown in figure 1. The process is then proceeded by the nodal analysis phase at the bottom-hole as indicated in Figure 1 showing a N/A symbol indicating nodal analysis. It then generated an IPR and outflow performance curve as indicated in figure 2 The results shows that the curves pass through the operating points of bottom hole pressure of 2172.829 Psia and well fluid flow rate of 786.3491stb/day.

Tubing size sensitivity analysis test was further carried out using a range of tubing sizes from 1.9 to 7 inches as shown in Figure 3.

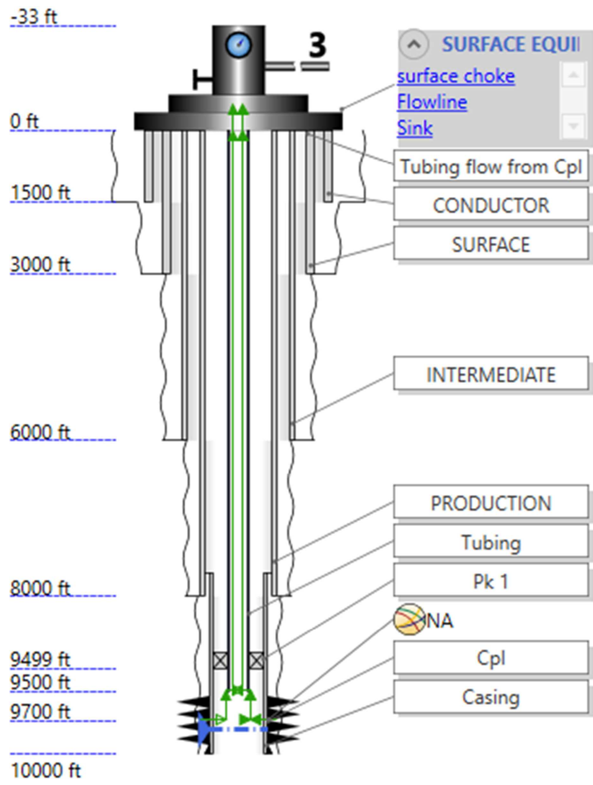


Figure 1. *Well XYZ.*

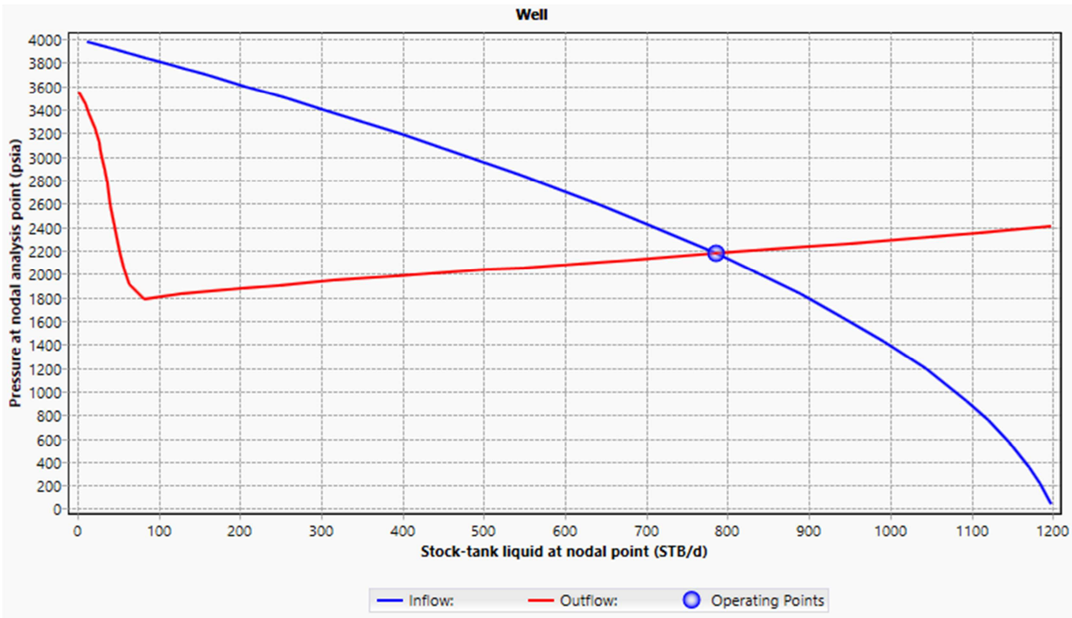


Figure 2. *IPR and VLP curve of Well XYZ.*

4.1. Result of Sensitivity Test

Figure 3 shows results of the tubing performance of different tubing sizes for well XYZ and they are summarized in Table 1 which is further analyzed in figures 4 and 5.

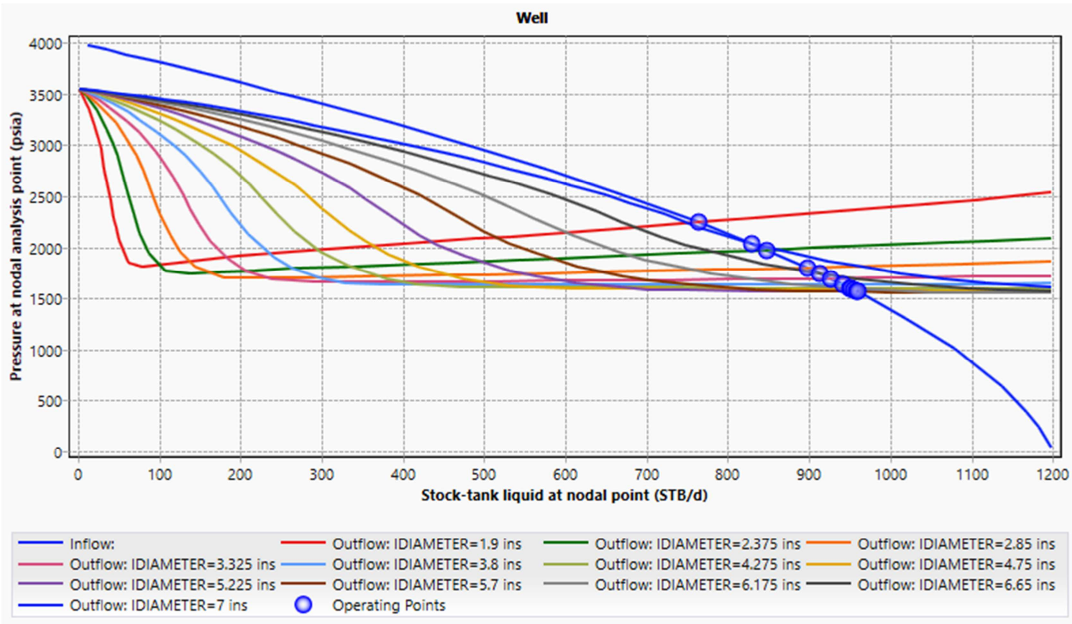


Figure 3. *Effects of various tubing diameter size on inflow performance curve vs outflow performance curve of well XYZ.*

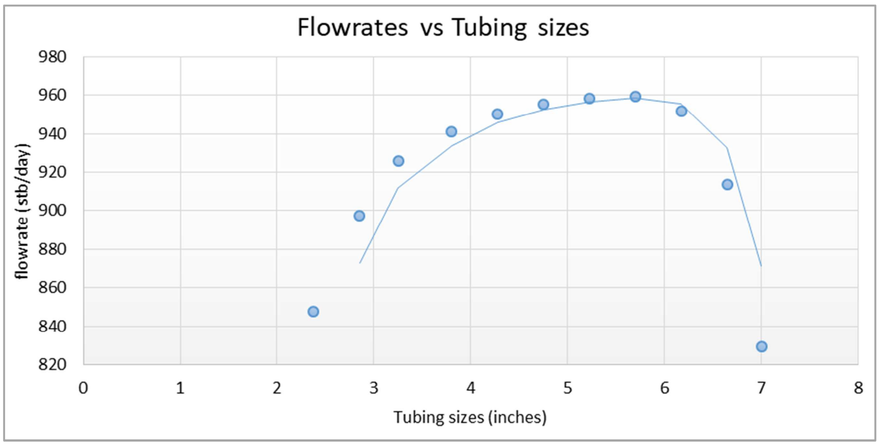


Figure 4. *Plot of Flow rate Vs Tubing sizes.*

Table 3. *Optimal flow rate and pressure for different tubing sizes.*

Tubing size, ID (inches)	Flowrate (stb/day)	Pressure (psia)
1.9	763. 6803	2242.626
2.375	847.7949	1973.58
2.85	897.6228	1799.917
3.25	925.9318	1694.95
3.8	941.1729	1698.302
4.275	950.1762	1600.888
4.75	955.1532	1581.053
5.225	958.2438	1568.64
5.7	959.2692	1564.505
6.175	951.8662	1594.174
6.65	913.5425	1741.493
7.0	829.1195	2036.005

The flow rate versus tubing sizes plot data was generated from the tubing size sensitivity analysis result (Table 4) The plot shows that flow rate increased progressively within tubing sizes range of 2.375-inch to 4.75-inch, while tubing sizes greater than 4.75-inch to 5.70-inch showed highest flow rate performance. Consequently, those greater than 5.70-inch to 7.0-inch showed significant flow rate decline. The aforestated analysis therefore, shows that tubing sizes within the range of 5.225-inch to 5.70-inch will produce the well XYZ at optimum flow rate.

The Pressure versus tubing size plot data was again, generated from the tubing size sensitivity analysis (Figure 5). The plot shows a relative pressure drop within the range of less than 2.375-inch to 4.275-inch, while within the ranges of greater than 4.75-inch to 5.70-inch show also a relative stable and lowest pressure rates and then increases again in ranges greater than 5.70-inch. Based on the plot analysis, it clear that ranges within 5.225-inch to 5.70-inch tubing sizes will make the best choice for well XYZ development in terms of well control and longevity in well service life.

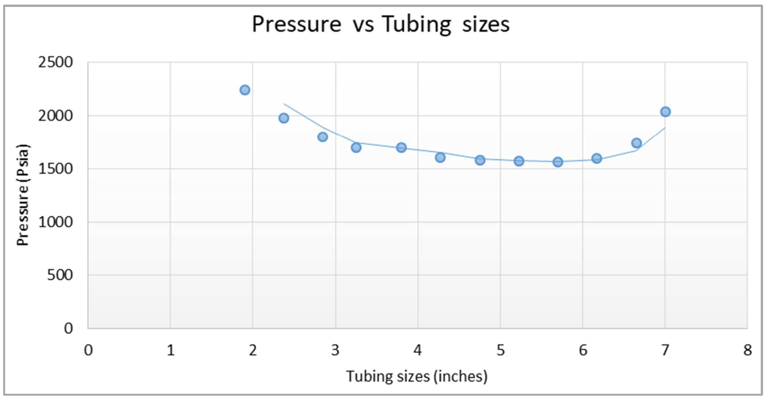
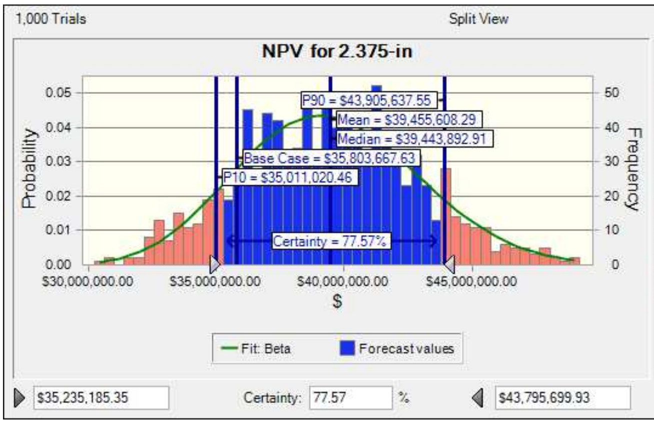


Figure 5. *Plot of Pressure Vs Tubing sizes.*

4.2. Monte Carlos Simulation Results for Some Selected Profitability Indicator

The stochastic results of the Monte Carlos simulation of the model for some selected metric system measures considering four tubing sizes which includes; 2.375, 3.325, 5.225, 6.65inches, are now presented in this sub-section. The selected indictors were carefully to justify the research objectives.

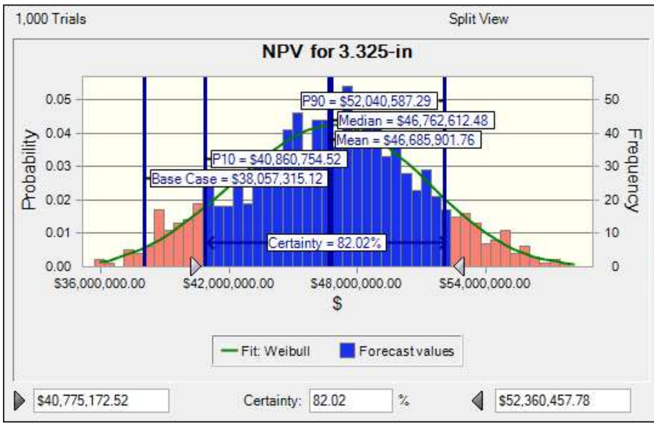


Statistic	Fit: Beta	Forecast
Trials	---	
Mean	$39,455,608.29	$39,455
Median	$39,335,304.58	$39,443
Mode	$39,074,611.64	
Standard Dev	$3,479,409.26	$3,481
Variance	$12,106,288,802.0	$12,118,40
Skewness	0.1927	
Kurtosis	2.88	
Coeff. of Vari	0.0882	
Minimum	$24,493,143.92	$30,240
Maximum	$65,573,614.64	$51,198
Mean Std. Err	---	$110

Figure 6. *NPV Result for 2.375-inch tubing size.*

4.3. Net Present Value (NPV)

The result of the stochastic modelling for a 2.375-inch tubing size (Figure 6), shows that on a 10% probability scale, the well has the capacity to generate an NPV less than or equal to $35,011,020.46 while on a 90% scale it has the capacity to generate an NPV less than or equal to $43,905,637.55.



Statistic	Fit: Weibull	Forecast
Trials	---	
Mean	$46,705,929.64	$46,685
Median	$46,729,010.13	$46,762
Mode	$46,866,510.50	
Standard Dev	$4,173,209.25	$4,173
Variance	$17,415,675,425.5	$17,415,67
Skewness	0.0113	
Kurtosis	2.71	
Coeff. of Vari	0.0894	
Minimum	$33,329,457.00	$35,719
Maximum	Infinity	$59,525
Mean Std. Err	---	$131

Figure 7. *NPV Result for 3.325-inch tubing size.*

The result of the stochastic modelling for a 3.325-inch tubing size (Figure 7), shows that on a 10% probability scale, the well has the potential of generating an NPV less than or equal to $40,860,754.52 while on a 90% scale it has the capacity to generate an NPV less than or equal to $52,040,587.29.

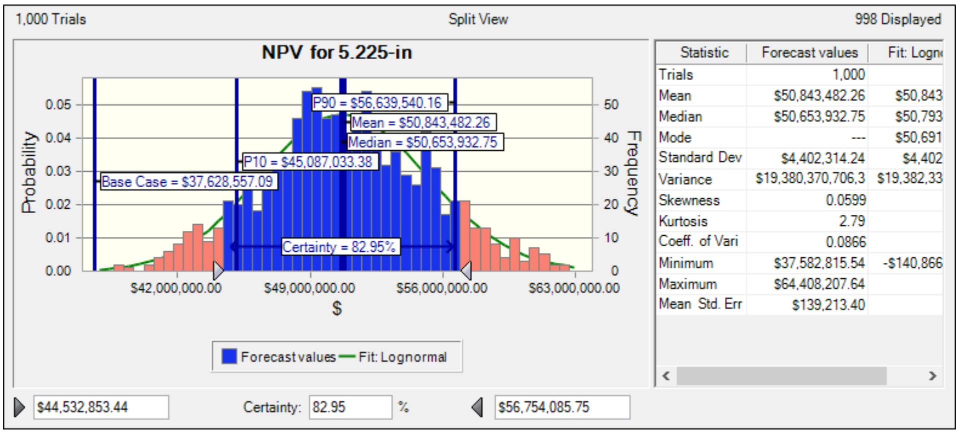


Figure 8. *NPV Result for 5.225 tubing size.*

The result of the stochastic modelling for a 5.225-inch tubing size (Figure 8), shows that on a 10% probability scale, the well has the potential of generating an NPV less than or equal to $45,087,033.38 while on a 90% scale it has the capacity to generate an NPV less than or equal to $56,639,540.16.

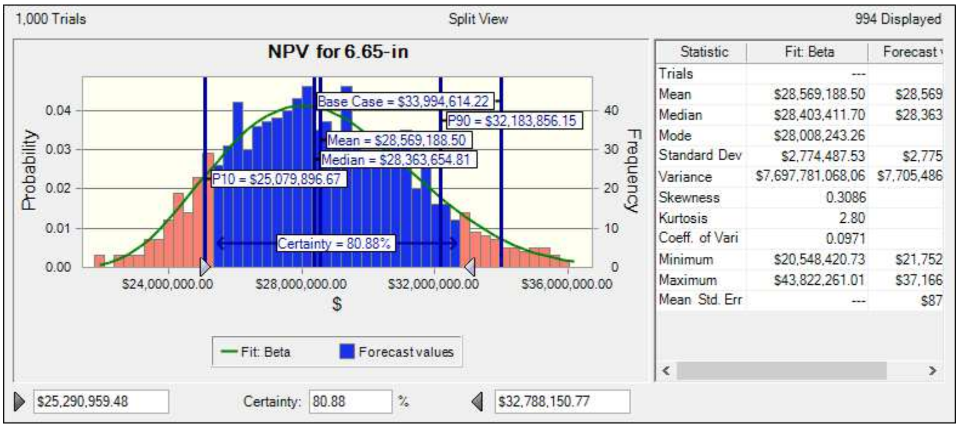


Figure 9. *NPV Result for 6.65-inch tubing size.*

The result of the stochastic modelling for a 6.65inch tubing size (Figure 9), shows that on a 10% probability scale, the well has the capacity to generate an NPV less than or equal to $25,079896.67, while on a 90% scale it has the capacity to generate an NPV less than or equal to $32,183,856.15.

4.4. Internal Rate of Return

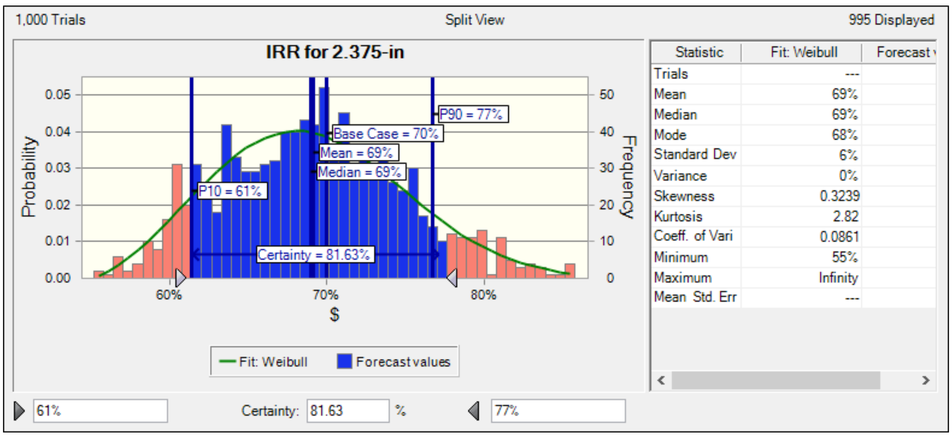


Figure 10. *IRR Results for 2.375-inch tubing siz.*

The IRR result of the stochastic modelling for a 2.375-inch tubing size (Figure 10), shows that on a 10% probability scale, using a 2.375-inch will generate an IRR of 61%, while on a 90% probability scale it will generate an IRR of 77%.

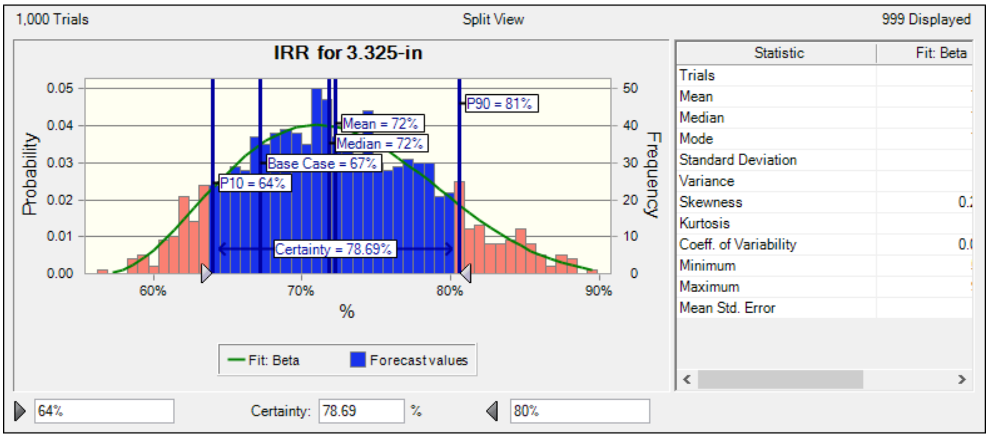


Figure 11. *IRR Results for 3.325 tubing size.*

The IRR result of the stochastic modelling for a 3.325-inch tubing size (Figure 11), shows that on a 10% probability scale, using a 3.325-inch will generate an IRR of 64%, while on a 90% probability scale it will generate an IRR of 81%.

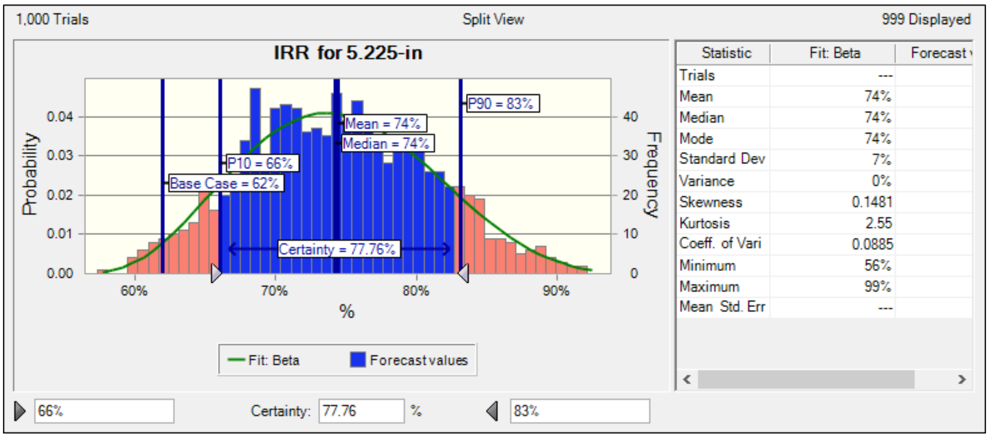


Figure 12. *IRR Results for 5.225-inch tubing size.*

The IRR result of the stochastic modelling for a 5.225-inch tubing size (Figure 12), shows that on a 10% probability scale, using a 5.225-inch will generate an IRR of 66%, while on a 90% probability scale it will generate an IRR of 83%.

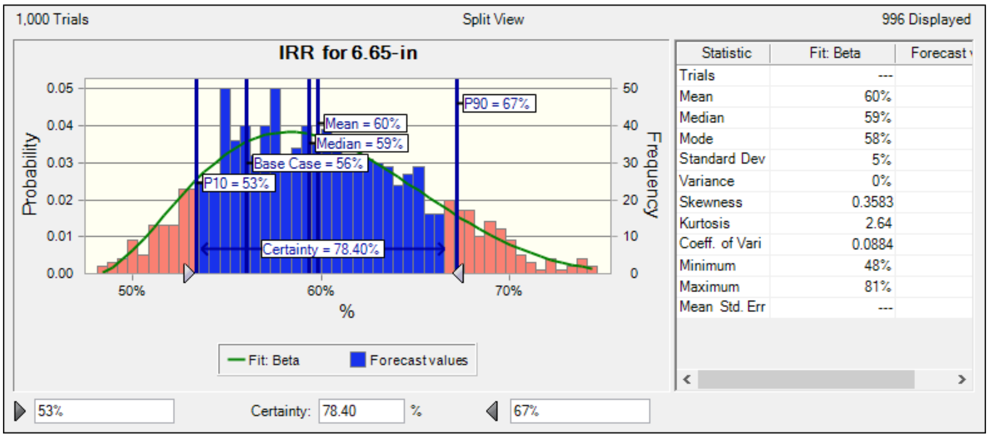


Figure 13. *IRR Results for 6.65-inch tubing size.*

The IRR result of the stochastic modelling for a 6.65-inch tubing size (Figure 13), shows that on a 10% probability scale, using a 6.65 -inch will generate an IRR of 53%, while on a 90% probability scale it will generate an IRR of 67%

Profitability index (PI)

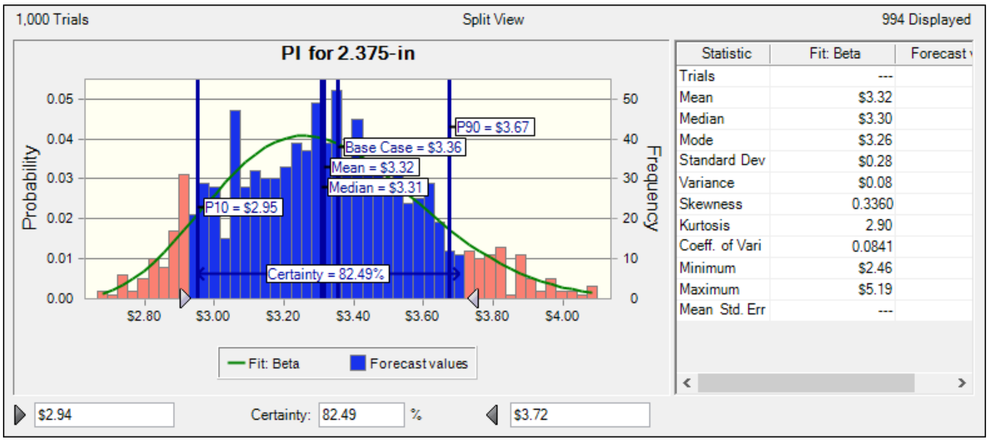


Figure 14. *PI results for 2.375-in tubing size.*

The PI result of the stochastic modelling for 2.375-inch tubing size (Figure 14), shows that on a 10% probability scale, using a 2.375-inch will generate an PI of 2.95, while on a 90% probability scale will generate a PI of 3.67.

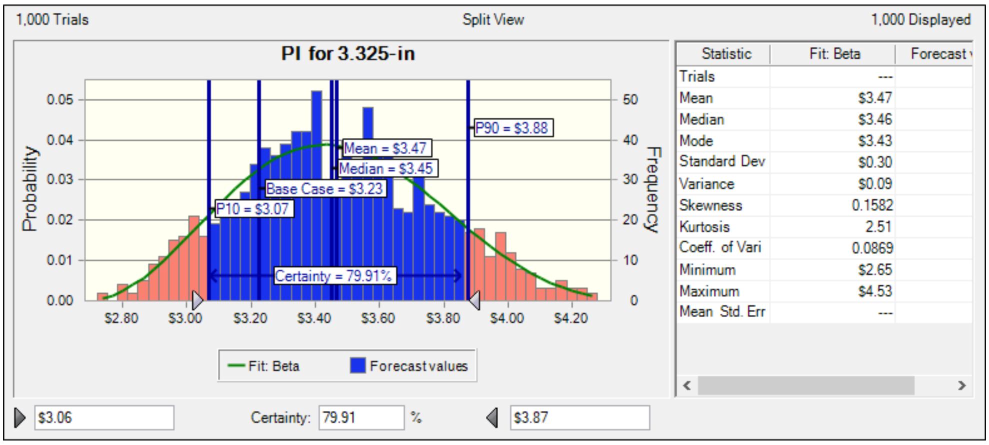


Figure 15. *PI results for 3.325-in tubing size.*

The PI result of the stochastic modelling for 3.325-inch tubing size (Figure 15), shows that on a 10% probability scale, using a 3.325-inch tubing size will generate a PI of 3.07, while on a 90% probability scale will generate a PI of 3.88.

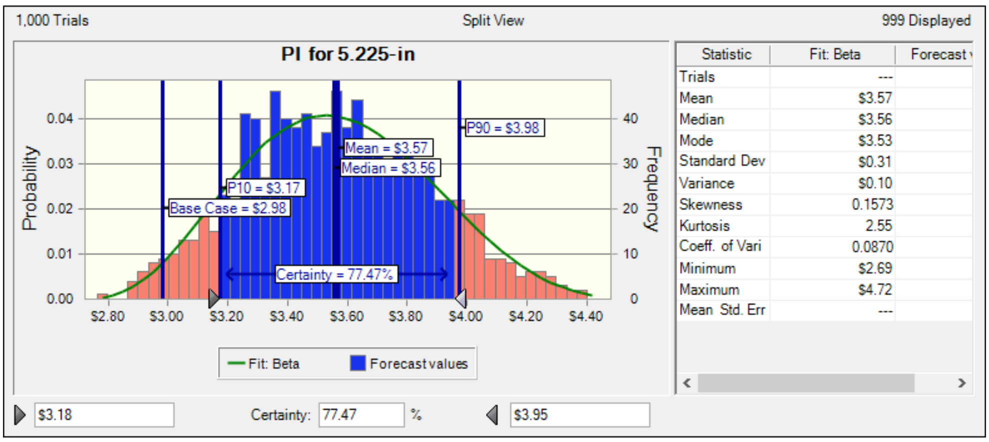


Figure 16. *PI results for 5.225-in tubing size.*

The PI result of the stochastic modelling for 5.225-inchtubing size (Figure 16), shows that on a 10% probability scale, using a 5.225-inch tubing size will generate a PI of 3.17, while on a 90% probability scale will generate PI of 3.98.

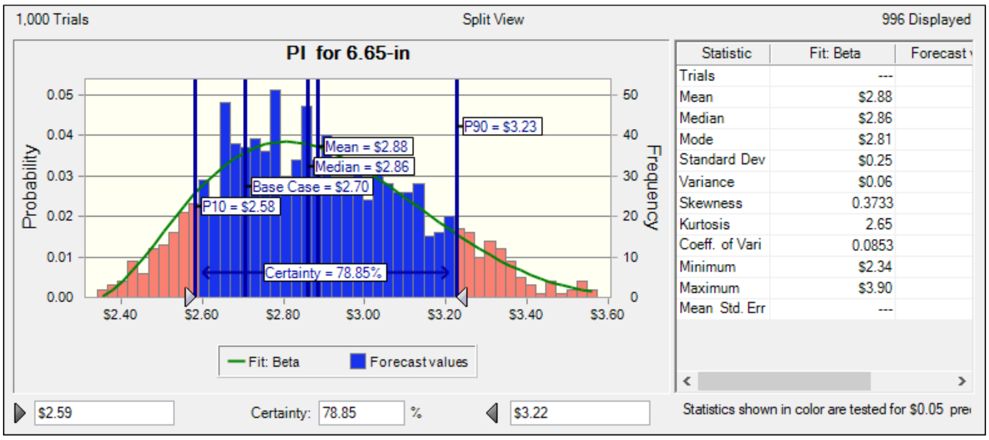


Figure 17. PI results for 6.65-in tubing size.

The PI result of the stochastic modelling for 6.65-inch tubing size (Figure 17), shows that on a 10% probability scale, using a 6.65-inch tubing size will generate a PI of 2.58, while on a 90% probability scale will generate a PI of 3.23.

4.5. Payout Period

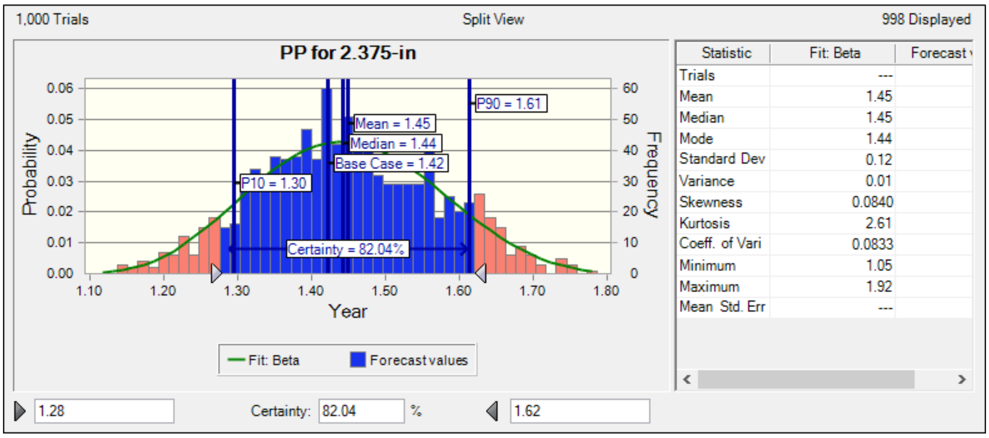


Figure 18. PP results for 2.375 in tubing size.

The PP result of the stochastic modelling for 2.375-inch tubing size (Figure 18), shows that on a 10% probability scale, using a 2.375-inch tubing size will operate a Payout period of a year and 3 months, while on a 90% probability scale will operate a Payout period of a year and 6 months.

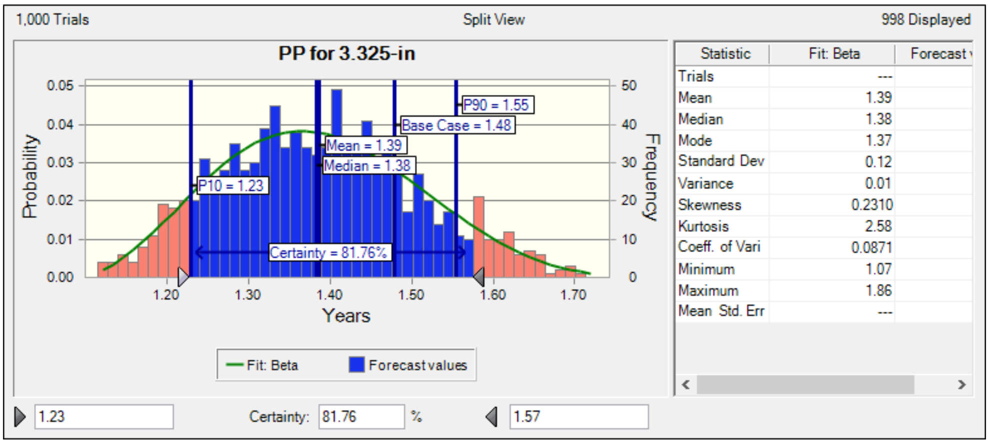


Figure 19. PP results for 3.325-in tubing size.

The Payout period result of the stochastic modelling for 3.325-inch tubing size (Figure 19), shows that on a 10% probability scale, using a 3.325-inch tubing size will operate a Payout period of 1 year and 2 months, while on a 90% probability scale, will operate a Payout period of 1 year and 5 months.

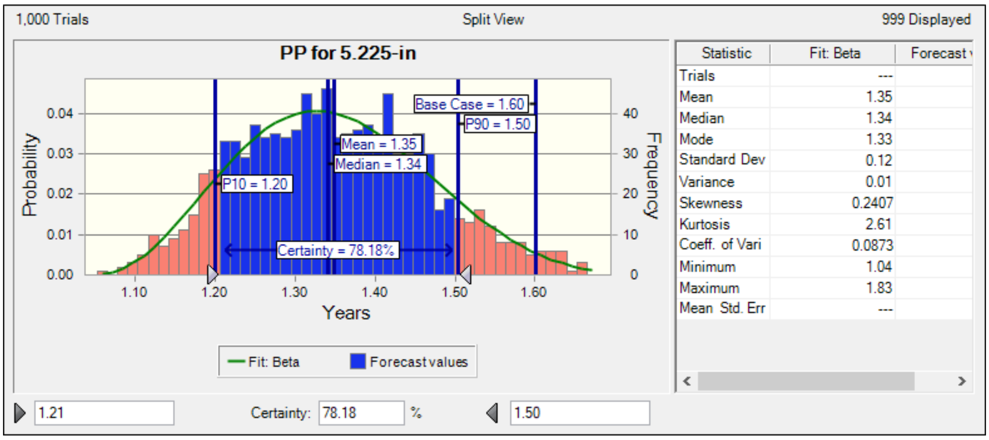


Figure 20. *PP results for 5.225 -in tubing size.*

The Payout period result of the stochastic modelling for 5.225-inch tubing size (Figure 20), shows that on a 10% probability scale, using a 5.225-inch tubing size will operate a Payout period of 1 year and 2 months, while on a 90% probability scale, will operate a Payout period of 1 year and 5 months.

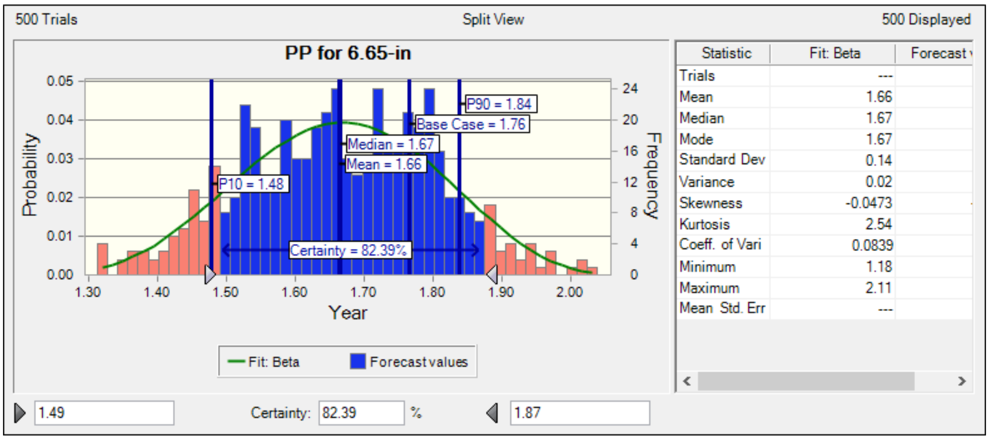


Figure 21. *PP results for 6.65-in tubing size.*

The Payout period result of the stochastic modelling for 6.65-inch tubing size (Figure 21), shows that on a 10% probability scale, using a 6.65-inch tubing size will operate a Payout period of 1 year and 4 months, while on a 90% probability scale, will operate a Payout period of 1 years and 8 months.

Table 4. *Profitable Indicators of Different Tubing Sizes and their Ranking.*

Tubing size (Inches)	NPV	IRR	PI	PP	Ranking
2.375	43,905,637.55	77	3.67	1.66	3rd
3.325	52,040,587.29	81	3.88	1.55	2nd
5.225	56,639,503.16	83	3.98	1.50	1st
6.65	32,183,856.15	67	3.23	1.84	4th

4.6. Sensitivity Analysis Results

This analysis was carried out to evaluate much impact some of input variables such as the price of oil, tubing costs, etc. have on the profitability indicators. The input variables impact each profitability indicator differently and would be observed. The analysis shows how much corresponding changes the profitability indicator would undergo with change in particular input variable. Its usefulness in decision making cannot be overemphasized as most of these variables could change over time. It therefore gives decision makers an idea of project's outcome, negative or positive, if a particular variable changes.

Briefly described below are the results of the sensitivity analysis done on the various profitability indicators on the four tubing sizes.

The sensitivity result given in Figure 22 shows that the input variable with the greatest impact on the NPV of the tubing sizes is the oil price which is directly proportional to the NPV. This implies that the higher the oil price, the higher the NPV. While tubing cost shows a negative impact, indicating the lower the tubing cost, the higher the NPV.

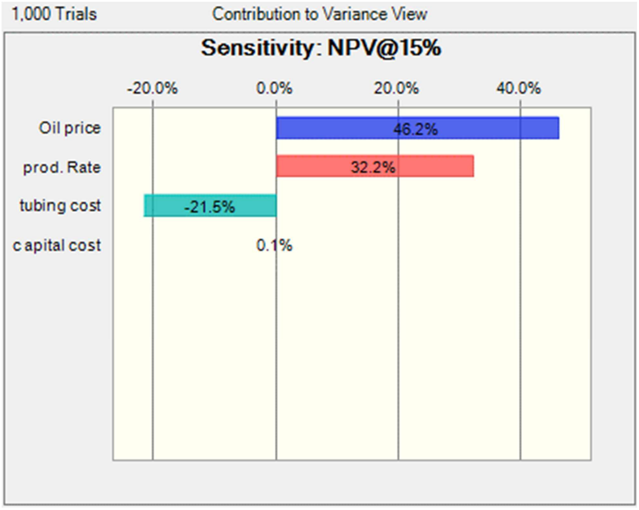


Figure 22. *Sensitivity Analysis on NPV.*

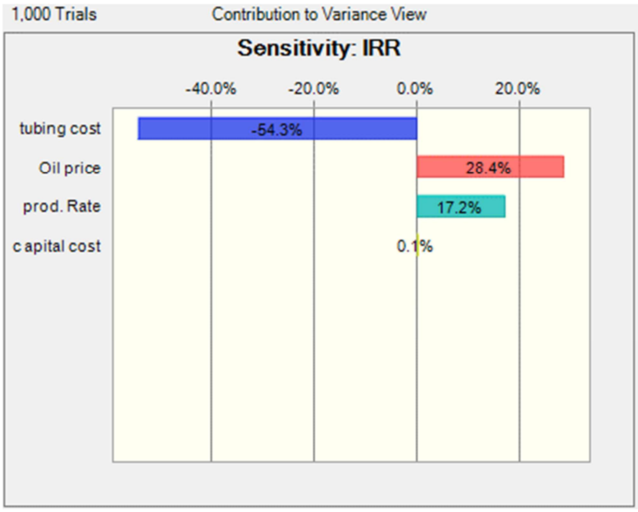


Figure 23. *Sensitivity Analysis on IRR.*

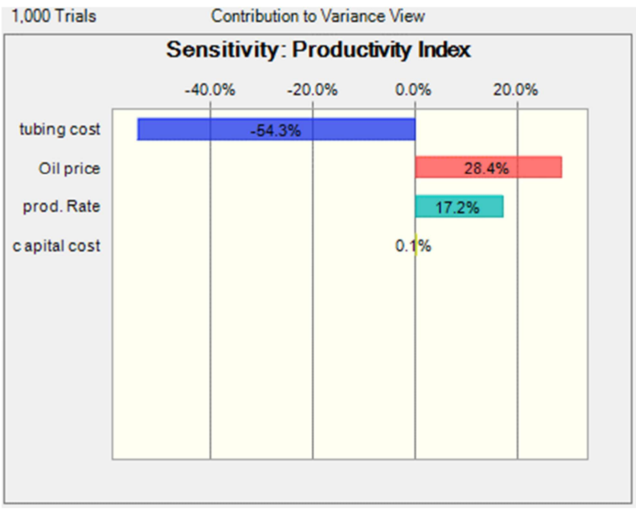


Figure 24. *Sensitivity Analysis on P1.*

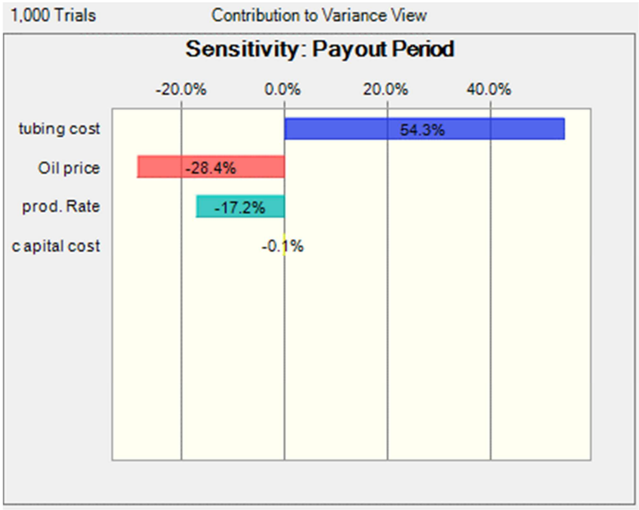


Figure 25. *Sensitivity Analysis on PP.*

The sensitivity result given in Figure 23 on the other hand shows a different trend. The figure above (figure 23) shows that the input variable with the greatest impact on the IRR of the tubing sizes is the tubing cost. The tubing cost shows a negative impact, indicating the lower the tubing cost, the higher the IRR. While oil price and production rate show a positive impact on IRR.

It was also observed in the sensitivity result given in Figure 24 that tubing costs shows the highest impact on PI. The figure above (figure 24) implies that the lower the tubing cost, the lower the tubing cost the higher the PI. While oil price and production rate show a positive impact on PI.

The sensitivity result given in Figure 25 shows that the input variable with the greatest impact on the PP of the tubing sizes is the tubing cost which is directly proportional to the PP. This implies that the higher the tubing cost, the higher the PP. While oil price and the production rate show a negative impact on the PP.

5. Conclusions

This study has been able to prove and further emphasize the importance of tubing size evaluation, it further buttresses that a field is not profitable, irrespective of the hydrocarbon reserve it may have until effective production design programs is developed such that the wells are produced optimally without compromising or risking operations while achieving peak economic advantage.

This research work has extensively analyzed four tubing sizes for both well XYZ, in bid to determine the optimum tubing size suited for the well with cost considerations that support best economic benefits of the wells without compromising well service life and safety of staff and environment. The aforestated task was carried out using Schlumbergers [10] for nodal analysis and consequent tubing size sensitivity test, while Oracle's CRYSTALBALL was used to carry out the economic analysis of the overall operation in relation to the tubing sizes in order to determine best economy friendly tubing size irrespective of their production and cost performance. Result of the nodal analysis carried out on all four tubing sizes on well XYZ show a relatively progressive increase in flowrate within the tubing sizes of 1.9-inch to 5.70-inch with stability point within the ranges of 5.225-inch to 5.70-inch and then declined within tubing sizes greater than 6.175-inch. Pressure report show reverse relative decrease with tubing sizes from of 1.90-inch to 4.275-inch, while ranges greater than 5.225-inch to 5.70-inch show lowest pressure rates and further increases afterwards with ranges greater than 6.175-inch. The study further progressed to economic analysis, using four profitability indicators in order to establish beyond reasonable doubts the tubing size that meet optimum criteria for the well in terms of profitability without compromising well life and safety of crew and environment.

The four profitability indicators explored in the study include Net present value (NPV), internal rate of return (IRR), Payout period (PP), and Profitability index (PI). Result of the economic analysis ranked the 5.225-inch tubing size highest across all four profitability indicators (Table 4) on an overall performance. Result of the sensitivity analysis carried out on all four profitability indicators show that tubing cost poses over 50% sensitivity on profitability in Internal rate of return (IRR), Payout period (PP) and Profitability index (PI) with over 25% of sensitivity and over 20% of sensitivity controlled by oil price and production rate respectively. On the other hand, for NPV, oil price control over 49% sensitivity to profitability while over 40% and 10% sensitivity is controlled by production rate and tubing cost.

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