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Decline Curve Analysis and Production Forecast Studies for Oil Well Performance Prediction: A Case Study of Reservoir X

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--***ABSTRACT***--
This paper focused on predicting the future production rate of an oil well using decline curve analysis and reservoir simulation. KN well 2A was used as the case study.Based on past production history, standard curves were generated usingexponential, hyperbolic and harmonic decline model equations from which comparative study of production decline rate trend analysis was carried out. The model equations were used to project future oil productions for a period of20 years. The exponential, hyperbolic and harmonic decline models yielded cumulative production values of 1117857 bbls, 1537573 bbls and 1871021 bbls, respectively.Also, history match was performed to evaluate the production behaviour of the field. Several simulation cases were run to assess the reservoir energy (pressure) and the field water cut in relation to oil production from the well in the reservoir investigated.Afterwards,production forecast modelwas built followinga field development plan to project the yearly and cumulative oil productions of the field from 2015 to 2035. Results from the production forecast showed that, a cumulative production value of 196.13 MMbbls and recoverable reserves estimate of 303.86 MMbbls were obtained. These were compared with field production history with ramifications, 84.17% accuracy.

KEYWORDS: *decline rate trend analysis,production forecast,history matching, reserves estimation*

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I. INTRODUCTION

Petroleum Engineers face the difficult task of predicting the future life of producing wells in a petroleum reservoir and more significantly estimating recoverable oil and gas reserves. This has been a major challenge in the oil and gas industry over years.For this, oil and gas productions and reserves have to be properly forecasted. Wrong forecast of oil and gas productions can lead to insignificant cost and failure of various oil recovery techniques. Several techniques have been adopted in literature to predict the amount of oil and or gas production rate with time. These include the material balance, decline curve analysis, volumetric calculations, pressure transient analysis and reservoir simulation, among others. However, decline curve analysis has proved to be one of the most commonly method for determining the most probable future life of wells and estimation of its future production when there is available and sufficient production history data.

The total productivity of every well depends largely on its flow rate. Depending on the rate at which the reservoir fluid is being delivered to the surface, the future performance can be forecasted. Therefore, it is abundantly clear that, the characteristics of a reservoir can be effectively predicted by performing production decline rate trend analysis. This basically involves extrapolating the trend of certain reservoir parameters and variable characteristics of the producing wells. Using production history acquired over several years or months, decline curves can be used to determine the future production and ultimate recovery with some level of accuracy since it utilizes curve-fit of past performance (Anyadiegwu*et al.*,2018).

Many researches such as those conducted by Fetkovich (1984),Blasingame *et al* (1989), Hubbert and Robertson (2004), Agrawal and Gardner (2008), have applied the decline model concept in diverse ways to forecast future oil and gas productions. Fetkovich (1984) in his study applied the decline concept to predict oil and gas productions in comingled layered reservoirs. He adopted an advanced decline analysis approach applicable for drainage and pressure changeconditions. His approach was similar to pressure transient testing. In his research,it was stated categorically that under certain production conditions and scenarios, the initial rate does not decline significantly. Fetkovich finally concluded that the Arps empirical model equations are only applicable to rate-time depletion data.

Blasingame *et al* (1989) introduced the type curve decline concept to analyze pressure transient data with analytical harmonic decline neglecting hyperbolic declines. The proposed hydrocarbon decline technique from Blasingame was not limited to constant flowing bottomhole pressure. Rather, it takes into consideration the changes in the flowing bottomhole pressure in transient phase.Hubbert and Robertson (2004) in their research modified the hyperbolic decline. They suggested that, the hyperbolic decline model sometimes yields unrealistically high reserve estimates.They made an assumption that, rate of decline starts at 30% of flow and usually decline in hyperbolic way. They further revealed that 10% decline rate of hyperbolic model can also be considered in production forecast.

Agrawal and Gardner (2008) built on Fetkovitch's and Palacio-Blasigame's methods and presented a modern decline types curves to analyze field production data. They introduced modern type curves utilizing dimensionless parameters on conventional well test data. Their concept was similar to Fetkovitch and Blasigame. However, they placed more emphasis on the importance of water influx in gas reservoirs. In their research, it was revealed that, less knowledge of the aquifer behavior and life span is a disadvantage and poses difficulties to model such reservoirs.The above reviews showedthat, the decline model concept is a reliable and efficient approach for performance prediction and determining the economic viability of oil and gas productions.

The most popular type of decline curve is the plot of production rates versus cumulative oil or cumulative gas production. It illustrates the decline in oil or gas production rate with time. It is also termed as rate-cumulative plots. More importantly, when there is no other injection project, oil production rate will decline with increasing production period. If the oil production rate decline to the expected economic limit (surface oil rate < 10 bbl/day), the producing well is considered to stop production (Khulud *et al.,* 2013).Mostly, the production decline observed should really portray the productivity of the reservoir. This should not be the result of other factors, such as control of production, equipment failure and change in well damage production conditions.In decline analysis, a stable reservoir condition must be considered in order to extrapolate decline curves with any degree of certainty. Normally, this condition is satisfied as long as mechanism to recover the oil is not disturbed and therefore various techniques are adopted to improve oil recovery such as miscible fluid injection, infill well drilling, hydraulic fracturing, matrix acidizing techniques. Also, production decline curve analysis can be used to predict the performance of the wells or the reservoir in the absence of the production change encountered compared to the actual performance(Vansandt *et al.,* 1998).

According to Arps (1945), there are three different types of decline curves. These are exponential, hyperbolic and harmonic decline curves. Among the three methods, only two methods are commonly used. Most petroleum reservoirs experience exponential and hyperbolic production decline but for comparison purpose, harmonic decline model is included in this work.Decline curve analysis concept has been used in different dimensions. However, the purposeof this study is to use the Arps decline curve analysis coupled with simulation technique to evaluate and predict future production of an oil well.

II. STUDY METHODOLOGY

2.1 Reservoir Description

The reservoir of interest synthetically called reservoir X, is one of the deepest reservoirs in the KN field, Gulf of Guinea.It is an elongated reservoir and thinned from the north to south direction towards the basin indicating a prograding sequence. The reservoir is a barrier type deposit. It is of good continuity with producing and injector wells present within the study area. It has very good flow and storage capacities.The sands units are predominantly coarse and fine grained.

The source rock of this reservoir is of marine environment constituting mainly of thick shale sequence, minor and major quantities of turbiditic sands in potential reservoirs within deep waters. The reservoir sands are characterized as unconsolidated sands interbedded with shale sequence(Stacher, 1995).

The reservoir of interest has an API gravity of 29̊. It is a black oil system. 14 active wells have been drilled in this reservoir within the study area. It is made up of seven deviated, two sidetracks, and five horizontal wells.Table 1shows thereservoir rock and fluid propertiesobtained from Onuh *et al*(2017). Detailed geological reservoir characterization study showed that the field investigated has produced 201 MMSTB of STOIIP and 4.6 BSCF of GIIP. Approximately 84 MMSTB of oil has been achieved, representing 42% field recovery.The field recorded an average water cut of 80% and production of 28.7 MBOPD in the year 2001 (Onuh*et al.*,2017).

Table 1: Reservoir rock and fluid properties

Property	Value
Datum depth	4600 ftss
Initial reservoir pressure, P_i	2010 psia
Bubble point pressure, P_b	1998 psia
FBHP (06,16)	1912 psia
Reservoir oil density	0.61 g/cc
Reservoir oil viscosity	0.50 cp
Proven oil column	170 ft
Boi @ P_i	1.636 rbl/stb
Initial Solution GOR, R_{si}	298 scf/stb
Reservoir Temperature	167˚F
Stock tank oil density	28.9˚API
Gas gravity (air = 1)	0.89
Rock compressibility	$3.00\text{x}10^{-6}$
Average porosity, φ	0.28 v/v
Average water saturation, S_w	0.20 v/v
Average permeability, K	3100 mD
STOIIP	201.0 MMSTB
N_p (06/16)	84.3 MMSTB
RF (06/16)	41.98 %

2.2 Methodand Data Used

A step-by-step methodology of using Arps (1945) model equations and stochastic (probabilistic) modeling technique are presented to predict future performance of an oil well in a reservoir within section of the KNfield. The dataset used in this study was obtained from theKN field.The scope of this researchconcentrates on predicting the performance of an oil well using decline curve analysis, performing history match to evaluate field development strategies (scenarios) and forecasting future oil production rate of the field from proposed development plan.The empirical equations were used to generate standard curves to predict future oil production rates and cumulative productions at specific periods. Production decline rate trend analysis was performed and the estimated oil productions from the model equations were compared in terms of respective tank values.Initialization run was conducted on the input data (models) prepared using eclipse 300 simulator and history matchingwas carried out. The history match data file was run and certain input parameters varied. This was done to match Field Pressure (FPR) and Field water cut (FWCT) in order to calibrate the proposed model of the field. The parameters varied were fluid saturation, relative permeabilities, transmissibility and pore volume. These parameters were varied to match FPR and FWCT of the model to the observed history data.Finally, production forecast model and volumetric reserve model were built for the field. The decline curve analysis and simulation technique demonstrated how the individual well and field performance trends may be significantly analyzed so as to provide detailed information about future production rate and the remaining oil reserves. Tools used in this research included: Schlumberger eclipse 300 and crystalballsimulators. The eclipse simulator was used to perform history matching. Crystalball simulator was used for production decline analysis and estimating reserves for the field. The results obtained were analyzed, discussed and conclusions drawn. Figure 1presents the work flow adopted in this study.

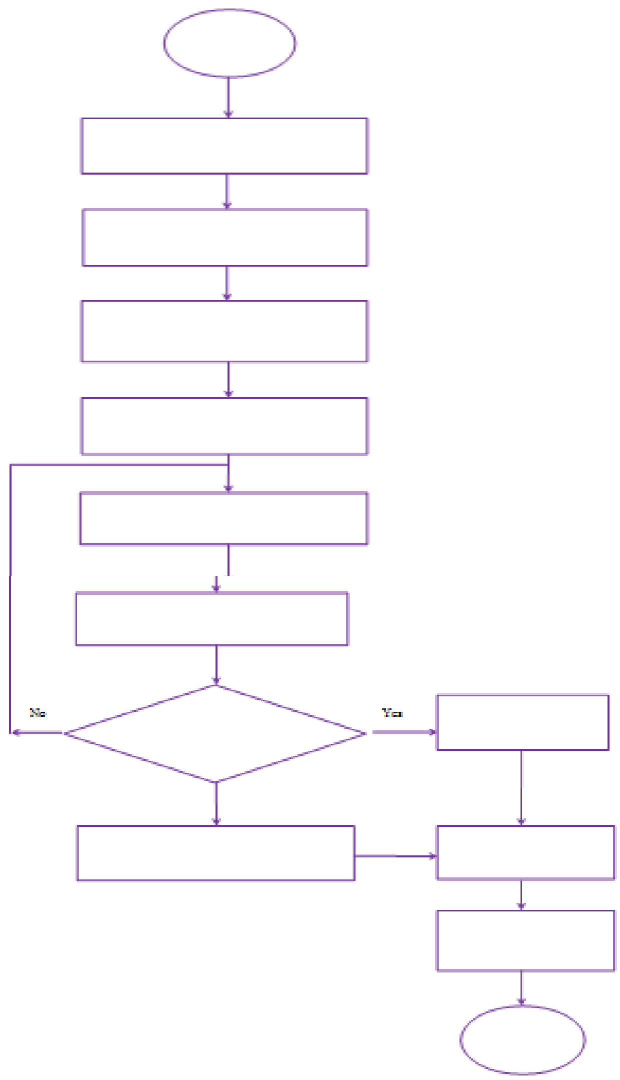

Figure 1: Flow chart of methodology used

2.3 Model Equations Used

Production performance datasets taken from the KN field were analyzed using various Arps (1945) model equations. The equations were applied assuming pseudo-steady state flow condition. The production data of the active well was used to describe the decline performance and to forecast the future oil-production rate for period of 20 years. The decline curve analysis is carried out using these empirical model equations given as follows:

Exponential decline model

The decline rate a does not varies with q; a = constant where d = 0

Production rate q at any time

$$q = \frac{q_i}{e^{at}} = q_i e^{-at} \qquad \text{(Equation 1)}$$

Cumulative oil production, N_p

$$N_p = \frac{1}{a}(q_i - q) = \frac{q_i - q}{a} \qquad \text{(Equation 2)}$$

Harmonic decline model
The decline rate a varies linearly with q; where d = 1
$$\frac{a}{a_i} = \frac{q_i}{q} \quad \text{(Equation 3)}$$
Production rate q at any time
$$q = \frac{q_i}{(1+a_i t)} = q_i(1 + a_i t)^{-1} \quad \text{(Equation 4)}$$
Cumulative oil production, N_p
$$N_p = \frac{q_i}{a_i} ln\frac{q_i}{q} \quad \text{(Equation 5)}$$

Hyperbolic decline model
The decline rate a varies geometrically with q i.e.*;* where 0<d<1
Production rate q at any time
$$q = \frac{q_i}{(1+da_i t)^{1/d}} \quad \text{(Equation 6)}$$

Cumulative oil production, N_p
$$N_p = \frac{q_i^d}{(1-d)a_i}[q_i^{(1-d)} - q^{(1-d)}] \quad \text{(Equation 7)}$$

Where:

q_i = initialoil production rate, stb/day
q = oil production rate, stb/day
a_i = nominal decline rate,year^{-1}
a =decline rate, year^{-1}
d = effective decline rate, year^{-1}
t= decline period, year
N_p= cumulative oil production, stb

III. RESULTS AND DISCUSSION

3.1Production Decline Curve Analysis

The performance of the well of interest is predicted using Arp's rate-time and cumulative-time plots as presented in Figures 2 and 3.In this study, we assumed a constant productivity index of the welland an idealized case of a reservoir.In this case, the reservoir is considered to be producing at a constant pressure in the absence of water drive.Hence, the pressure is assumed to be proportional to the amount of remaining oil.This hypothetical case suggests that there should be a linear relationship between the cumulative oil produced and the reservoir pressure and also the relationship between production rate and cumulative oil production observed. However, this theoretical condition does not occur in the case of dealing with an actual reservoir. As long as these conditions do not change, the trend in decline was analyzed and extrapolated to predict future performance of the studiedwell (KN Well 2A). The production history was essentially used to predict rate of flow from the well up till 2012. It is observed (in Figures 2 and 3) that the decline trends of the various models correspond to increase in cumulative productions and decrease in production rates over time. The decline could be attributed to the prevailing operational and reservoir conditions such as fluid withdrawals and pressure depletion from the reservoir.

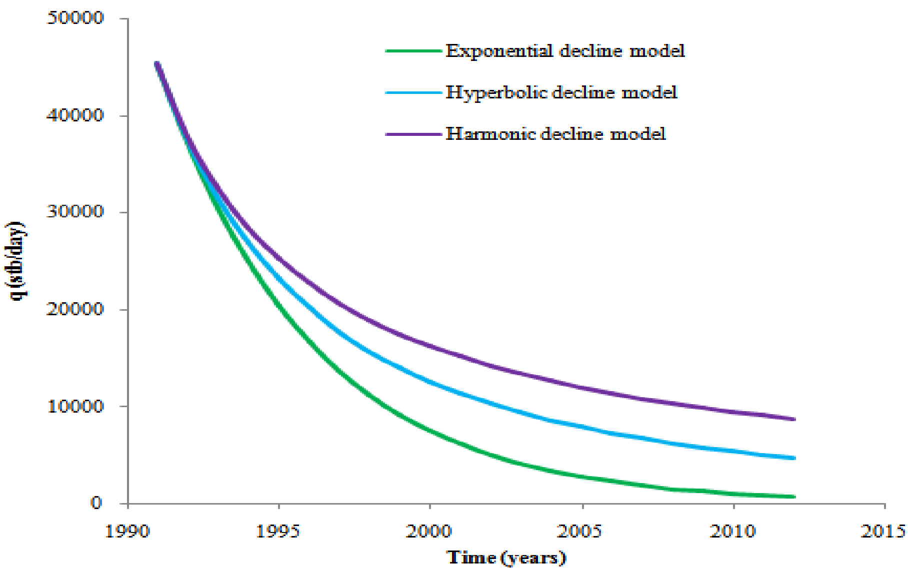

Figure 2: Production rate vs. time (1991-2012)

Comparatively, the harmonic decline model yielded unrealistically high cumulative oil value of 1,871,021 stock-tank barrels whereas exponential model predicted very lower values than the hyperbolic model. This is because the hyperbolic standard curve continually flattens with time since decline rate is no longer constant but varied over the prediction period. Also, exponential model predicted the least cumulative production value of 1,117,857 stock-tank barrels over the decline period. However, the hyperbolic model predicted slightly higher cumulative value of 1,537,573 stock-tank barrels compared to the exponential model. The production rates for harmonic, hyperbolic and exponentialmodels at the end of the decline period were 8730 stb/day, 4724 stb/day and 681stb/day, respectively.

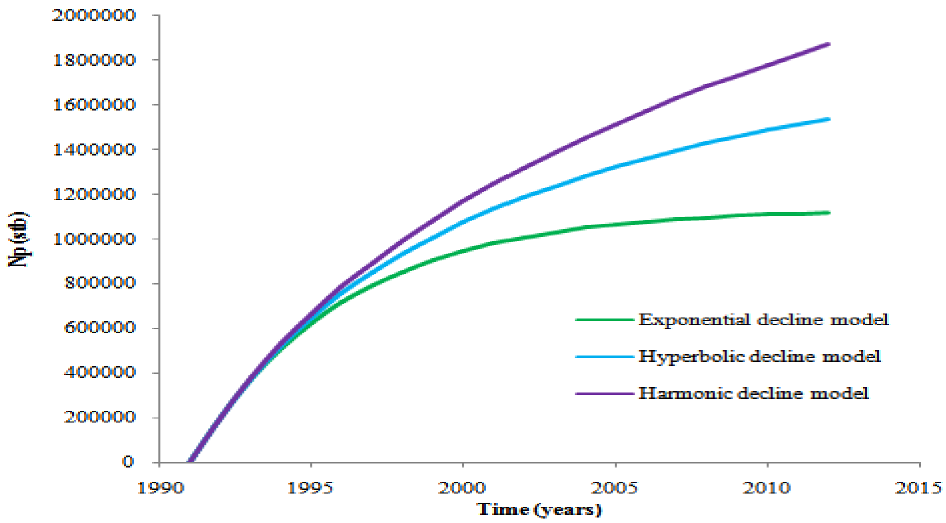

Figure 3: Cumulative production vs. time (1991-2012)

Table 2: Production History of KN Well 2A

Year	Time, year	Production rate q, stb/day	Cumulative oil production Np, stb
1991	1	45,395	-
1992	2	37,166	205,718
1993	3	30,429	374,146
1994	4	24,913	512,042
1995	5	20,397	624,943
1996	6	16,700	717,378
1997	7	13,673	793,057
1998	8	11,194	855,018

3.2History Matching

In history matching, after a model has been constructed, it must be tested to determine whether it can duplicate field behaviour. Generally, the reservoir description used in the model is validated by running the simulator with historical production and injection data and comparing calculated pressure and fluid movement with the actual reservoir performance. In this study, history matching was performed on certain reservoir parameters which included: pressure and saturation. The essence of this task was to evaluate the impact of field water cut in relation to water breakthrough and the reservoir pressure for the purpose of pressure maintenance across the field during oil production. Comparatively, the properties of the well and the field were almost the same, after and before the adjustment of the various input parameters for the history matching and prediction.Twelve simulation runs were performed to validate the proposed model for the saturation match whereas nine simulation runs were performed to validate the model for the pressure match. Both models were constrainedto pore-volume for Field Pressure (FPR) (energy balance) andfluid saturation for Field Water Cut (FWCT).Figures 4 and 5 present results from the simulations runs. The black dots, pink curves, yellow curves, blue curves, green curves, red curves, among others are model responses for observed/historical data, respectively.In all the casesconsidered for pressure and saturation match, the proposed modelsindicated an appreciable match.

3.2.1 Saturation Match

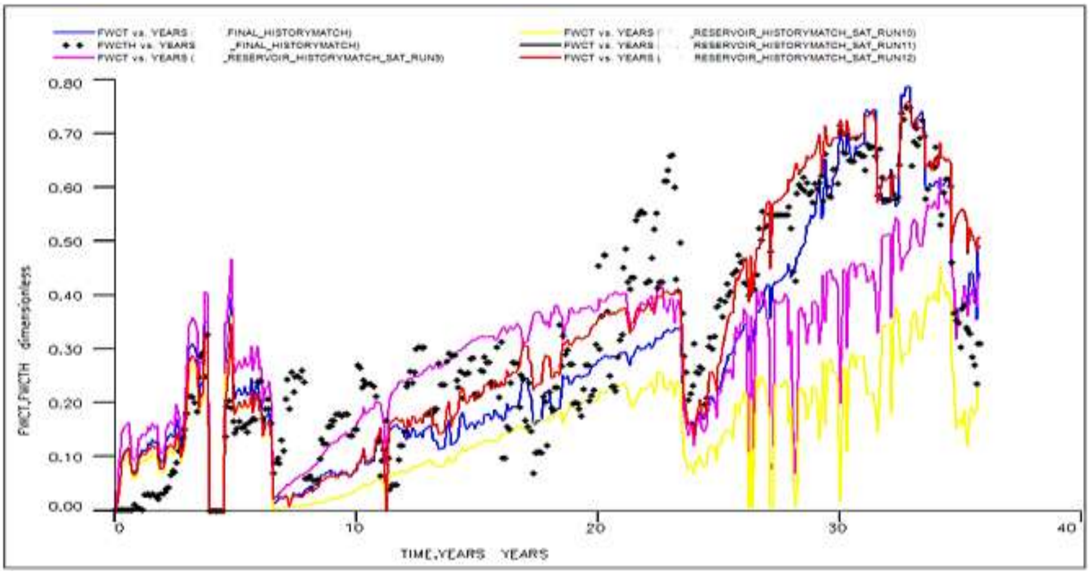

Figure 4: Dynamic simulation results for saturation match

The black dots, blue lines and red lines, among others represent historical/measured data.

3.2.2Pressure Match

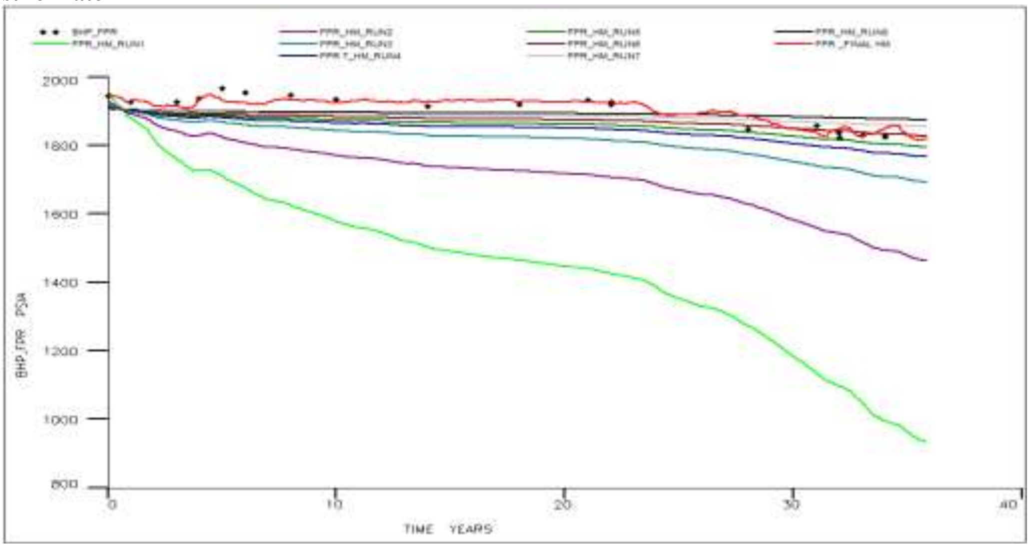

Figure 5: Dynamic simulation results for pressure match

The black dots, blue lines and red lines, among others represent historical/measured data.

3.3Production Forecast

The production forecast model was built using stochastic modeling technique based on the field development plan from the operating company. A program was developed in crystal ball to forecast the annual and cumulative productions. From the production forecast and profile(in Figure 6), it is estimated that the cumulative production before the sale of the asset (oil field) peaked at 185,942,802 bbls. However, after imposing the necessary assumptions and running the simulation; it was estimated that the cumulative productions fall between 189.43 MMbbls and 200.10 MMbbls at 50% confidence interval with 84.17% accuracy. The production of hydrocarbon fields goes through various distinct stages. When an oil reserve is discovered, an appraisal well is drilled to evaluate the reservoir potential. The next phase refers to the first oil produced and indicates the build-up phase onset. As production continues, its rate reaches a plateau and then finally arrives at the depletion starting point. In order to slow down or delay the production downfall, it means, extending the production plateau, an efficient reservoir management plan will have to be put in place. The cumulative production and remaining reserve till 2035 were estimated to be 196,139,205 bbls and 303,860,795 bbls. The remaining reserve was obtained by subtracting the cumulative oil production at the end of 2035 from the size of discovery. Figure 6illustrates the production profile for the field over 20 years of production period. Table 4 shows the results obtained from the simulated production forecast for the field of interest.

Table 3: Field development plan

Production forecast input parameters	
Production began at	3 years
Initial production	1000 BOPD
Instantaneous production year	2015 year
Peak production	50000 BOPD
Peak production begins	2018 year
Peak period	4 years
Effective decline rate	0.125/year
Field life	20 years
Number of days/year	365 days
Size of discovery	500,000,000 bbls

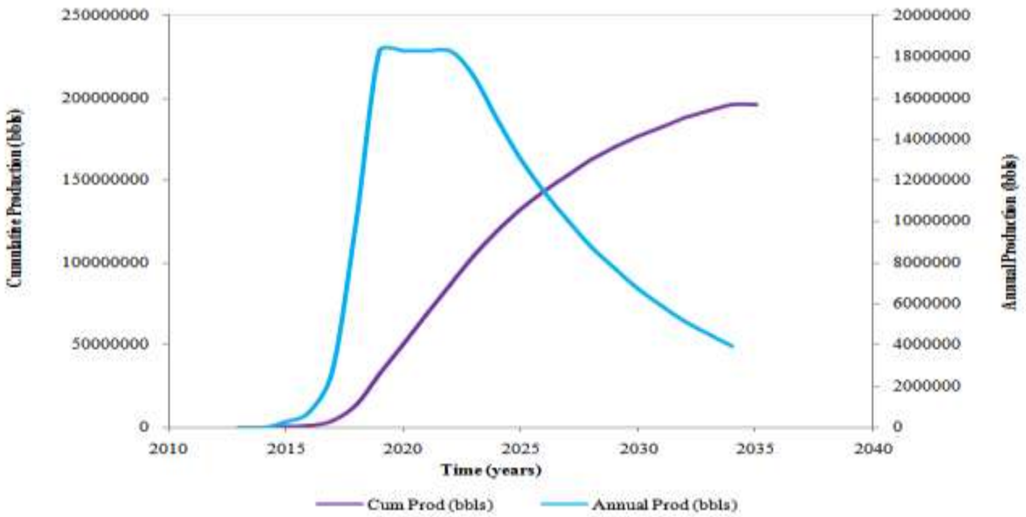

Figure 6: Production profile for the fieldof interest

Table 4: Results for simulated forecast

Year	Rate (BOPD)	Annual Prod (bbls)	Cum Prod (bbls)
2012	-	-	-
2013	-	-	-
2014	-	-	-
2015	1000	279906	279906
2016	3684	751277	1031184
2017	13572	2767730	3798913
2018	50000	10196403	13995316
2019	50000	18250000	32245316
2020	50000	18250000	50495316
2021	50000	18250000	68745316
2022	50000	18250000	86995316
2023	43750	17083998	104079314
2024	38281	14948498	119027812
2025	33496	13079936	132107748
2026	29309	11444944	143552692
2027	25645	10014326	153567017
2028	22440	8762535	162329552
2029	19635	7667218	169996771
2030	17180	6708816	176705586
2031	15033	5870214	182575800
2032	13154	5136437	187712238
2033	11510	4494383	192206620
2034	10071	3932585	196139205
2035	8812	-	196139205

3.4Reserve Estimation and Statistical Analysis

Volumetric reserve estimationmodel was generated for the field using stochastic modeling technique. The input parameters for this model across the field included: water saturation value of 20.0%, oil formation volume factor of 1.636rb/stb, average porosity of 28.0%, thickness of 42 ft, drainage area of 1000 acres and a field recovery efficiency of 41.98%. The model was built at 5% precision based on assumptions using 1000 trials. The estimated reserve (N_p) is a lognormal distribution with a mean of 13,458,032 stb and a variance of 12,350,775,338.47 sq. stb. The results captured the uncertainty in the reserve prediction. After imposing the necessary assumptions and running the simulation, it is estimated that the maximum value of reserve peaked at 28,117,894 stb at 50% confidence interval.The model showed an estimated median value of 12,996,174 stb with a standard deviation of 3,514,367 stb. However, the minimum value of reserve estimated was 815,410 stb.The proven, probable and possible reserves were estimated as: 9,402,185 stb, 12,996,174 stb and 18,094,425 stb, respectively. Table 5 summarizes the results of the simulated reserve estimations for the field. Figure 7 shows the results for the reserve estimation model.

Table 5: Results for simulated reserve estimation

Reserve	Percentile	Estimated value (stb)	Precision (%)
Proven	P90	9,402,185	3.42
Probable	P50	12,996,174	3.16
Possible	P10	18,094,425	3.13

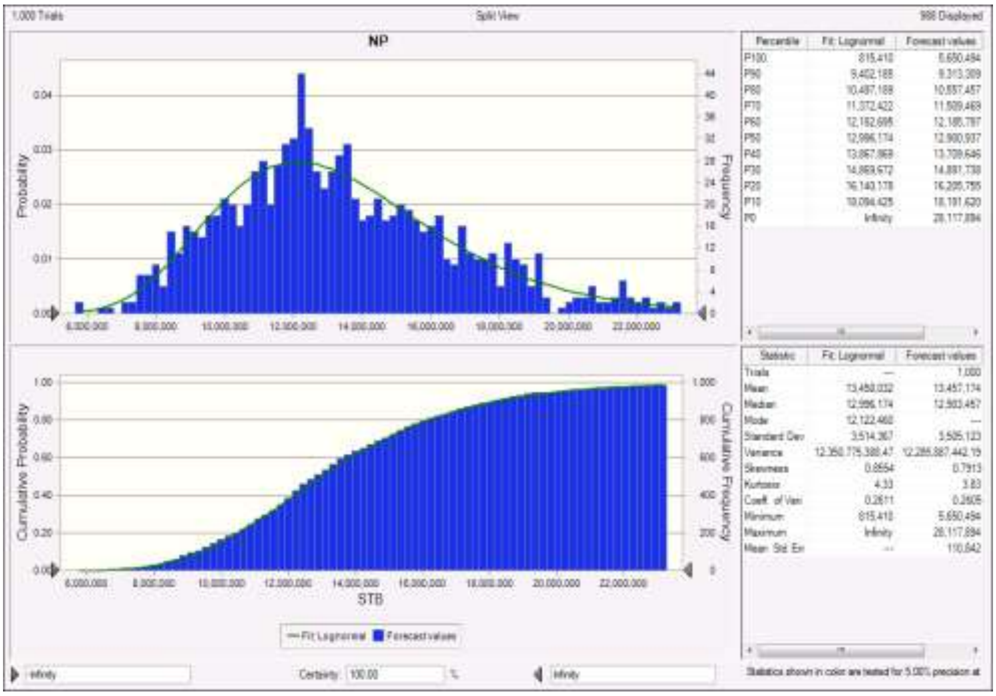

Figure 7: Volumetric reserve estimation model for the field

IV. CONCLUSIONS

The following conclusions were drawn from the results obtained in this study. The production decline rate trend analysis, revealed an increase in cumulative oil productionsand a decrease in production ratesover the periods. The exponential, hyperbolic and harmonic decline models yielded 1117857 bbls, 1537573 bblsand 1871021 bbls, respectively. The decline rates for harmonic, hyperbolic and exponential models till 2012 were estimated as: 8730 stb/day, 4724 stb/day and 681stb/day. The dynamic simulation results of the proposed modelsfor pressure and saturation showed appreciable match to evaluate the field performance. Results from the production forecast showed that, a cumulative oil production value of 196.13 MMbbls and remaining reserves estimate of 303.86 MMbbls were obtained.The volumetric reserve estimation model for the fieldclassified the estimated reserves into proved, possibleand probable.The proven, probable and possible reserves estimated are 9,402,185 stb, 12,996,174 stb and 18,094,425 stb, respectively. The study demonstrated the efficacy of using decline curve analysis and simulation approach for well performance prediction.

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