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Economic Evaluation of Nigerian Marginal Oil and Gas Field using Financial Simulation Analysis

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ABSTRACT

Marginal oil and gas field could contribute immensely to wealth creation, employment generation and confidence in local oil firms if properly exploited by the indigenous firms. Despite the laudable marginal field initiative by the government, indigenous players still face challenges in exploiting these fields in Nigeria. This study evaluates the fiscal regime and the economic factors that could be hindering oil field development among the indigenous oil firms. The result of the financial cash flow modelling found that the marginal oil field's project is viable with post-tax net present value (NPV) and expected monetary value above $29 million. The petroleum profit tax, royalty and crude oil price have more impacts on the field's NPV. The study suggests a periodic assessment of the fiscal regime and appropriate policy by the government to encourage the local players in developing the marginal oil field.

Keywords: Indigenous, Marginal Oil and Gas Field, Financial Simulation, Government
JEL Classifications: F38, Q47

1. INTRODUCTION

The development of marginal oil and gas field among the indigenous firms has become a topical issue in Nigeria. Many oil fields have been left undeveloped and termed "marginal" by the International Oil Companies (IOCs) since the exploration of petroleum started in the 1930s in Nigeria (Offia, 2011). This is not unconnected with the volume and cost of oil and gas in such fields which do not meet the investment hurdle of the company. Meanwhile, international investors are faced with capital constraints and therefore rank their projects in order to obtain the greatest return from a limited budget. This restricts the IOCs from developing such fields but rather use the capital to develop commercial fields in other parts of the world. This definitely reduces the amount of revenue accrued to government and employment opportunities that should ordinarily be created if these fields are producing. Thus, the Federal Government of Nigeria came up with marginal field development initiative with a view to increasing the daily production of oil from 2.4 million barrels/day to 4.0 million barrels/day and increase the reserves to over 40 billion barrels of oil, increase indigenous participation in oil and gas industry, generate more employment opportunities and develop indigenous capacity. This is expected to strengthen the local content strategy in the oil and gas sector.

There is a reported huge reservoir of marginal oil fields in Nigeria conservatively estimated to contain over 2.3 billion barrels of stock tank oil initially in place strewn over 183 marginal fields (Onyeukwu, 2010). In 2003, the Federal Government handed over the operations of 24 marginal fields to 31 Nigerian companies hoping that the confidence of the local players would improve in the exploration and production of oil and gas activities. The government wanted to achieve the farm-out of marginal fields within the concessions of the IOCs to indigenous companies. Despite this laudable policy, the success of the indigenous players can be said to be very "insignificant." Not many have made appreciable progress with their concessions as only 6 out of the 24 marginal fields are producing presently which is not moving in tandem with the desired pace for the local content development (Adetoba, 2012). It is therefore necessary to know what could be responsible for this unimpressive trend in marginal oil and gas field development by the indigenous oil companies in the country.

A number of studies have been conducted on the technological (Kaiser, 2010; Offia, 2011; Devold, 2013; Akinwale, 2015) and economic factors (Ayodele and Frimpong, 2003; Iledare, 2004; Adenikinju and Oderinde, 2009; Adamu et al., 2013) affecting oil and gas field development across the globe and Nigeria in specific. However, there is still a dearth of information on the economic and fiscal uncertainties affecting the indigenous marginal field operations in the Nigerian oil and gas sector. This study contributes to the existing research by providing an economic analysis of the marginal oil field being operated by the indigenous oil firms in Nigeria. This paper comprises five sections which include Section 1 introduces the research paper, Section 2 discusses the Nigerian oil and gas industry as well the fiscal regime, Sections 3 and 4 discuss on methodology and analysis while section 5 provides recommendation and conclude the paper.

2. OVERVIEW OF NIGERIAN OIL AND INDUSTRY AND THE FISCAL REGIME

This section discusses the oil and gas industry in Nigeria, economic rent and fiscal regime and types of petroleum fiscal arrangement in Nigeria

2.1. Overview of Oil and Gas Industry in Nigeria

Hydrocarbon resources mainly oil and gas have become the main stay of the Nigerian economy in terms of revenue for government, contribution to gross domestic product and sources of foreign exchange earnings. The history of oil and gas industry in Nigeria can be traced back to 1908 when a German Company, the Nigerian Bitumen Corporation and British Colonial Petroleum started prospecting for oil (Nigeria National Petroleum Corporation, 2014). The emergence of the First World War led to the sudden stoppage of the company prospecting for oil (Okonmah, 1997). Oil prospecting activities recommenced around 1937 and 1938 when Shell D'arcy currently called Shell Petroleum Development Company of Nigeria was given the sole concession rights throughout Nigeria. The company continued to search for oil but was also disrupted by the Second World War, and thereafter continued to prospect for oil until the first oil was discovered in commercial quantity at Oloibiri, Bayelsa in the Niger Delta in 1956. Production and exportation did not start until 1958 when the first oil field came on stream producing 5.100 barrels of crude oil per day (bpd) (Odularu, 2007). The sole concession given to Shell BP was broken in the 1950s by giving some other multinational companies the right to search, win and produce oil (Hassan, 2013). Mobil oil corporations which started operations in 1955 became Mobil producing Nigeria Limited and then started production in 1970. Other multinational oil companies such as Texaco Overseas, Safrap (later Elf), Agip Oil, Phillips Oil and Gulf among others commenced operation in the 1960s (NNPC, 2014).

As at the end of 1960s, most of the oil companies that came from different parts of the world to prospect for oil and gas in Nigeria have started production. The oil boom of the 1970s led Nigeria to neglect its strong agricultural and light manufacturing bases in favour of crude oil. According to Ramlogan et al. (2009), the crude oil production was fairly small in 1963 with around 75,000 bpd being produced, peaking at over 2,000,000 bpd in 1973 as shown in Table 1. One of the major plans of the government is to raise this daily production to 4,000,000 bpd by year 2010 but this target has not been actualized due to many factors such as pipeline vandalisation, social unrests, technological and economic issues among others. Also, the contribution of crude oil to government revenue has increased drastically from less than = N = 8 million in early 1960s to more than = N = 8 trillion in 2012 and fell to = N = 6.8 trillion in year 2013 and 2014. Furthermore, the proportion of crude oil exports to total export has increased significantly from <10% in the early 1960s to above 90% in the 2000s but has been dwindling within the range of 95% and 97% for the past one decade (Ramlogan et al., 2009).

Table 1: Nigeria's crude oil production and revenue between 1963 and 2014

Year	Crude oil production ('000 barrels/day)	Crude oil revenue (in million naira)
1963	75	<8
1973	2055	1016
1983	1235	7253
1993	1985	162,102
2003	2263	2,074,281
2005	2580	4,762,400
2007	2356	4,462,910
2009	2120	3,191,938
2011	2457	8,878,970
2013	2302	6,809,230
2014	2361	6,793,720

Source: Ramlogan et al. (2009); BP Statistical Review of World Energy (2015); Central Bank of Nigeria Statistical Bulletin (2015)

2.2. Economic Rent and Fiscal Regime in Nigeria

The aim of any government in all oil and gas producing countries is to maximize its share in the economic rent generated from exploration activities and at the same time guaranteeing a reasonable return to the oil and gas companies carrying out such explorations (Kemp, 2011a; Omorogbe, 2005; Iledare, 2014).

Economic rent could be referred to as the true value of natural resource which is the difference between the revenues generated from resource extraction and the costs of extraction (Stauffer and Gault, 1985). Daniel et al. (2010) refer to economic rent as the surplus return above the factors of production employed to exploit the resource. Kemp and Stephen (2007) refer to economic rent as the return in excess of supply price of investment.

A fiscal regime can be defined as the framework which the government of an oil producing country employs in managing, regulating and sharing the revenues that accrue from all the stages of exploitation (Isehunwa and Uzoalor, 2011). It is a key factor in decision making by host governments and investors (Luo and Yan, 2010).

The fiscal regime currently operated in Nigeria can be broken down into joint ventures (JVs) and the production sharing contracts (PSC). Both the government/NNPC and oil companies entered into contracts in the two kinds of fiscal regime. The Nigerian oil industry was initially dominated by concessionary fiscal system where Shell D'arcy (later Shell-BP) was firstly given the only rights to search and explore for hydrocarbons in the 1930s. This was later extended to other IOCs in the 1960s. The average of the government stake of 60% in the IOCs though increased the government participation in the oil and gas industry but has equally left the government with the burden of funding 60% of the financial commitment of its JV with the IOCs which the government found difficult to meet (Ameh, 2005).

Consequently, the policy of the government began to shift from JV contracts to PSCs as a result of various challenges to meet its share of capital requirement in the oil and gas development. The increased use of PSCs in Nigeria in recent years has largely been a response to this drawback since government has no funding commitment under this arrangement because the oil and gas companies are fully responsible for the costs of exploration, development, and operation (World Bank, 2014). The PSCs encourage deep sea exploration, attractive royalty rates and other incentives among other things. Under PSC, the oil company bears all the costs and risks of exploration and development with no right for repayment in case there is no discovery leaving the host government with little or no risks to bear (Johnson, 1994; Nakhle, 2008). However, once a discovery is made, the company is allowed to recover the costs they incur and this is called cost recovery or cost oil.

3. METHODOLOGY

This section presents a detailed description of the engineering economic techniques adopted for the valuation of the viability of marginal oil and gas project. The economic analyses involved cash flow modelling, project profitability and sensitivity analysis (Adamu et al., 2013). This section explained influence diagram, discounted cash flow method (DCF) and Monte Carlo simulation used in this study.

3.1. Influence Diagrams

This is a visual representation or graphical picture of a decision problem. It helps to link relationship between decision and uncertainties and how they influence each other (Phimister, 2011). In order to present a clear diagram of the DCF model constructed in determining the economic viability of the hypothetical marginal field, a few number of influence diagrams was used to show this. Figure 1 shows the first influence diagram of pre-tax net present value (NPV) when government taxes have not been incorporated into the model.

This was followed by Figure 2 which shows the influence diagram after taking into consideration various taxes and all the allowances so as to obtain the total tax charged on the positive accumulated net cash flow (NCF) of the marginal field operators in the model. Figure 3 shows the influence diagram when the taxes are incorporated to give post-tax cash flow and post-tax NPV. Also Figure 4 captures the "government take" in both PV term and money of the day (MOD) term. It explains how government take is obtained in PV term which is the total tax charge as a percentage of pre-tax NPV or in MOD which is the total tax charge expressed as a percentage of marginal field pre-tax cash flow.

3.2. DCF Method and Expected Monetary Value (EMV)

The DCF method is most suited for producing properties in which an income stream is likely and not speculative (Ayodele and Frimpong, 2003). This DCF technique reflects the time value of money and incorporates the risk of an investment by discounting the future cash flows using the company's discount rate against the investment cost. This method is widely adopted when evaluating oil and gas investments by oil and gas companies (Gustavson, 1999).

Figure 1: Influence diagram for pre-tax net present value

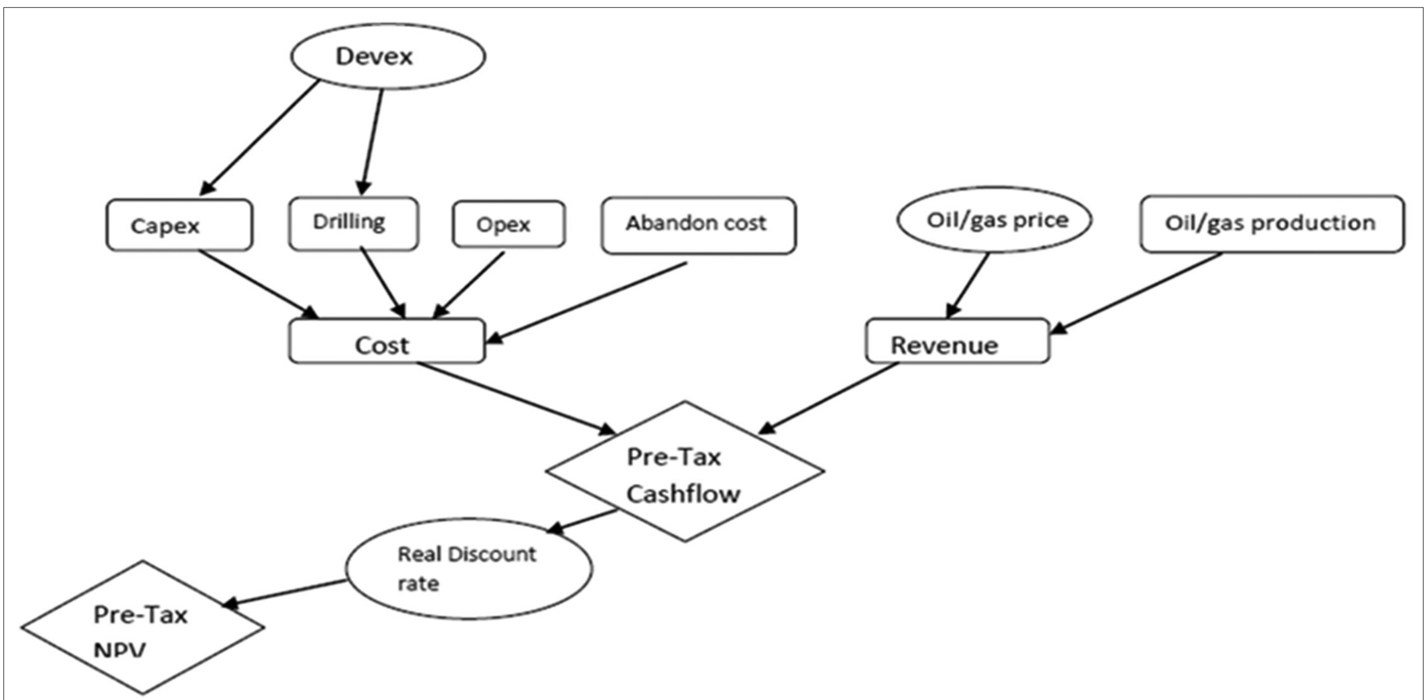


Figure 2: Influence diagram for the tax charged

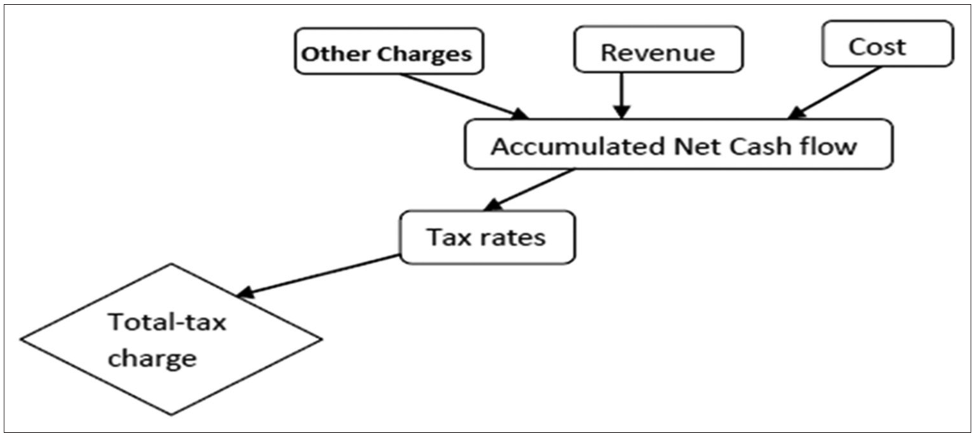


Figure 3: Influence diagram for post-tax net present value and internal rate of return

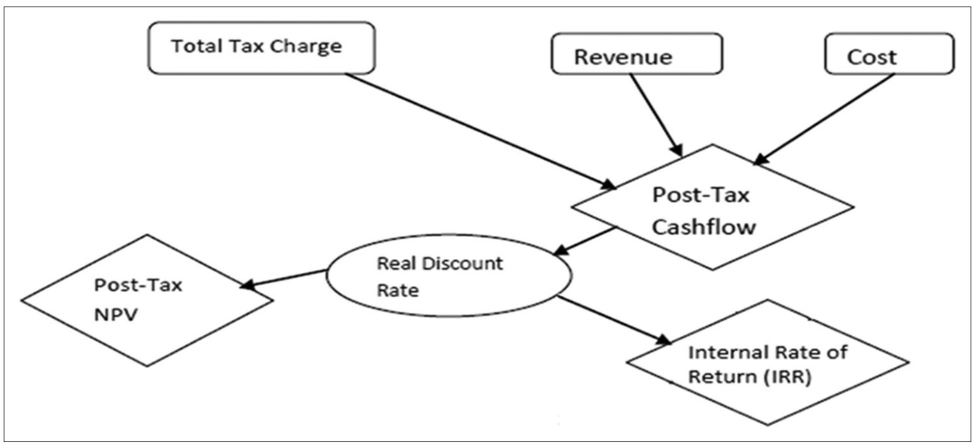
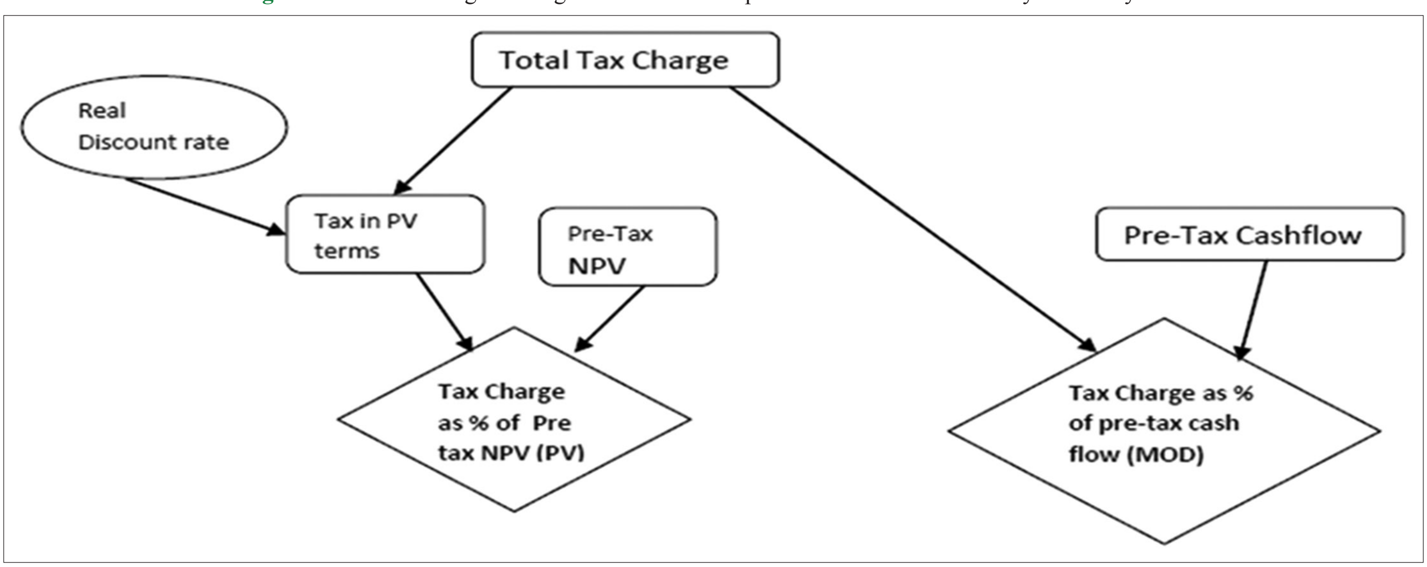


Figure 4: Influence diagram for government take in present value term and money of the day term



NPV criterion is the most popular investment criterion which is based on decision rule that a project with positive NPV should be undertaken while the one with negative NPV should be rejected because it is not profitable. The NPV can be expressed as:

$$NPV\left(r,t\right)=\sum_{i=0}^{N}\left(\frac{NCF(t)}{(1+r)^{t}}\right) \tag{1}$$

Where $NCF(t)$ = Estimated NCF over the time period t, r = Rate of discount.

When $NPV(r, t) > 0$ then the investment is profitable, otherwise the investment is not profitable. Meanwhile, internal rate of return (IRR) is the discount rate, which reduces the project NPV to zero. NPV of an oil and gas project is a function of oil and gas prices, total oil and gas production, development expenditure, operating expenditure, abandonment expenditure, real discount rate and government taxes among other factors.

Investors, especially the IOCs, are faced with capital constraints and therefore rank their projects in order to obtain the greatest return from a limited budget as well as to compare the investment opportunities in any region such as Nigeria to other parts of the world. Companies rank their project according to post-tax NPV/pre-tax investment ratio at 10% real discount rate; usually referred to as economic hurdle rate of NPV/I (Kemp, 2011b). A project is said to pass the economic hurdle and viable once this ratio is either above 0.3 or 0.5 (i.e., NPV/I ≥0.3 or NPV/I ≥0.5) depending on the extent of capital available for such company. Because of the marginality of this hypothetical field, an economic hurdle of NPV/I ≥0.2 was adopted.

EMV for oil and gas exploration is the NPV weighted by chance of discovery minus exploration and appraisal costs. This can be expressed in a simpler form below:

$$EMV = Pi*(NPVi) - E - P(A) \quad (2)$$

Where:
EMV = Expected monetary value;
Pi = Probability and/or chance of discovery;
$NPVi$ = Net present value of a given field;
E = Exploration cost,
A = Appraisal cost.

3.3. Monte Carlo Simulation and Sensitivity Analysis

Monte Carlo simulation is the use of sophisticated analysis by incorporating continuous distributions for the main primary variables. It describes the risks and uncertainties associated with the primary variables in the form of probability distributions. Crystal Ball package is a software tool that is very important for managing risk in a dynamic business environment. Analysing risk using crystal ball relies on developing a mathematical model in Excel spread sheet that represents a situation of interest (Adamu et al., 2013). The output that is forecasted can be used to assess the riskiness of the situation or it provides information needed to make more accurate, efficient and confident decisions. The primary variables in this case include oil and gas price, total oil and gas recoverable reserves, development expenditure, operating expenditure, taxes and abandonment cost. The distribution of outcome anticipated is then defined which is log normal. Simulation analysis consists of a series of repetitive calculations of value, NPV in this case, which will later generate EMV by obtaining expected value of NPV (i.e., EV[NPV)). Meanwhile, large number of simulation was undertaken to obtain stability in mean and standard deviation.

Sensitivity analysis using tornado chart and spider diagram was used to examine the effect of varying each primary variable on NPV. In other word, a sensitivity analysis was performed to determine the main factors causing the most variability in the NPV of a project (Luo et al., 2011). In summary, crystal ball was adopted to carry out the Monte Carlo simulation and the sensitivity analysis in this study.

3.4. Measurement of Variables

The fiscal structure and uncertainties affecting oil and gas field development was measured by the following variables:

1. Operating expenditure per barrel (Opex) of developing oil field
2. Capital expenditure per barrel (Capex) of developing oil field
3. Development expenditure (Devex)
4. Petroleum price per barrel
5. Decommissioning cost
6. Fiscal regime:
   - Petroleum profit tax (PPT)
   - Royalty
   - Education tax
   - Niger Delta Development Commission Tax (NDDCT).

The following assumptions were combined with those on Table 2 to construct the DCF models using excel spreadsheets:

a. The field is dominated by oil recoverable reserves with very little associated gas
b. The field is assumed to be one of the marginal field onshore
c. Oil price in base year is taken as \$60 per barrel, although sensitivity analysis was carried out to analyze different price scenario on the profitability of the field
d. The base year is 2015 taking into consideration that exploration has already been done in the past period, development activities to last within 2 years while production starts in 2017
e. Development cost per barrel constitutes 50% of capital expenditure and 50% of drilling expenditure. While the capital

Table 2: Oil field model assumptions

Base assumptions	Marginal oil field
Recoverable reserves or total oil production	20 mbbls
Base year	2015
Exploration period (year)	1
Production start year(immediately after exploration)	2017
Economic limit	2027
Real discount rate	10%
Total field production in million per barrel	20
Production declining rate	20%
Devex (\$) per barrel for new fields	6
Nigeria tax system	
Rate PPT	67.75%
RT	15%
ET	2%
NDDC	3%
Capital expenditure (% of Devex)	50
Drilling expenditure (% of Devex)	50
Abandonment cost (\$ per barrel)	1.50
Opex (\$ per barrel)	4
Phasing of development expenditure	
Capex (% of total capital expenditure) year 2015	100
Drilling expenditure (% of total drilling exp.)	60, 40
Drilling expenditure (years) from 2015	2
Abandonment cost (years)	1
Investment tax allowance	
(ITA) for indigenous marginal field operators	10%
Base price (\$) per barrel	60

Authors' Survey (2015); Ayodele and Frimpong (2003); NNPC (2014); Kemp (2011a), PPT: Petroleum profit tax, RT: Royalty tax, ET: Education tax, NDDCT: Niger Delta Development Commission Tax expenditure takes place in 2015, drilling expenditure takes place in 2015 and 2016

f. Discount rate is taken as 10% and constant over the entire project
g. The base oil price and field costs are also assumed constant throughout the projects' lifespan
h. The field produces at maximum capacity with 20% declining rate as the field matures
i. Availability of a ready market for the oil produced each year
j. Depreciation allowance of 20% for 5 years starting from 2017 when development expenditure must have been expended
k. Exploration and development costs are offset from the investment tax allowance of 10% per annum for the indigenous marginal field operators
l. Government take consists of PPT and royalty
m. Single (combined) tax is charged once the accumulated NCF turns positive.

Formula used for some calculations in the financial cash flow modeling:

This provides the formulae for some of the calculations used in preparing the DCF for the financial model constructed in this study

i. Yearly production = Production_rate*total field_production_20 Mbls
ii. Yearly revenue = Oil_price_barrel*yearly_production_20 mbbls
iii. Capex = Capex_rate*capex_percent devex*total devex
iv. Drilling cost = Drilling_rate*drilling_percent devex*total devex
v. Opex = Opex_dollar_perbarrel*yearly_production_20 mbbls
vi. Abandonment cost = Abandonm_rate*abandon_perbarrel*totfield_production_20 Mbls
vii. Total cost = Capex + drillingcost + opex + abandonment_cost
viii. Depreciation Allowance = Depreciation_allow rate*total devex
ix. Pre-tax NCF = Revenue_20 mbbls − total_cost − dep_allowance
x. Accumulated cash flow = Previous accumulated cash flow*(1 + investment tax allowance_rate) + pre_tax_NCF
xi. Tax due period = IF (Accumulated_cashflow >0,1,0)
xii. Tax base =Tax_Due*MIN (pre-tax NCF, accumulated cash flow)
xiii. Petroleum profit tax = PPT_rate*tax_base
xiv. Royalty = Royalty_taxrate*revenue_20 mbbls
xv. Education tax = Education_taxrate*tax_base
xvi. Niger delta development tax = NDDC_taxrate*tax_base
xvii. Total tax = PPT+ royalty tax+ education tax+ NDDCT
xviii. Post-tax NCF = Pre_Tax_NCF − Total_Tax
xix. Pre-tax NPV at 10% discount rate = NPV (real_discount_rate, pre_tax_NCF)*(1+real_discount_rate)
xx. Post-tax NPV at 10% discount rate = NPV (real_discount_rate, post_tax_NCF)*(1+real_discount_rate)
xxi. Investment hurdle rate (NPV/I) = Post_tax_NPV/total devex
xxii. Internal rate of return = IRR (post_tax_NCF)
xxiii. Total present value tax (total PV_tax) = Sum {total tax_government take/(1+real_discount_rate)^number of year}
xxiv. Government take in present value = TotalPV_tax/Pre_tax_NPV

4. DISCUSSION AND ANALYSIS OF RESULTS

This section provides the analysis which addressed the objective of the study. The study of economic viability of oil and gas projects especially marginal fields become so germane in deciding whether oil and gas firms will invest in such fields or not (Iledare, 2014; Johnson, 1994; Kemp, 2011b). An hypothetical marginal oil field operated by the indigenous oil firm is considered in this analysis, and all the assumptions related to it have been presented in Table 2 in the previous section.

4.1. Production Profile and Post-tax NCF of the Oil and Gas Field

Figure 5 shows that production from this hypothetical marginal oil field starts with 4.6 million barrels per annum (equivalent to 12,600 barrels of crude oil production/day) and ends with 200,000 per annum (equivalent to 548 barrels of crude oil production/day) by the year 2026. The economic limit which is the period which the crude oil production lasts is 10 years and decommissioning of the oil field will be done in year 2027. Figure 6 shows the NCF for the marginal oil field after the relevant tax must have been deducted. The NCF is negative in year 2015 and 2016 when capital costs are being incurred before commercial production starts. The NCF peaked at $127.8 million in year 2017 when oil was discovered in large quantities and started dwindling after falling from year 2018 to 2026 when it reduced to $1.5 million. The post-tax NCF becomes negative in year 2027 as a result of decommissioning costs which the firm incurs after reaching economic limit.

4.2. DCF Statement for the Marginal Oil Field Project using the Base Assumptions

Table 3 shows the result of the DCF statement developed for the base scenario of the Nigeria's hypothetical marginal oil field project showing the revenue, cost and fiscal regime. This takes into consideration the entire base assumptions in Table 2 in the previous section which are the input variables used to develop the financial model of Table 3. The result shows that with the base crude oil price of $60 per barrel and other assumptions as earlier stated, the hypothetical marginal oil field will generate $530.01 million as pre-tax NPV and $29.32 million as post tax NPV. This indicates that the marginal oil field project considered in this study is viable under the base scenario since the value of post-tax NPV is greater than zero. The investment hurdle rate (NPV/I) is 0.24

Table 3: Results of the base scenario

Output variables	Values at base scenario
Pre-tax NPV	$530.01 m
Post-tax NPV	$29.32 m
Investment hurdle rate	0.24
IRR	0.21
Government take	89.4%

NPV: Net present value, IRR: Internal rate of return

Figure 5: Yearly production of crude oil for the hypothetical marginal field (in million barrels)

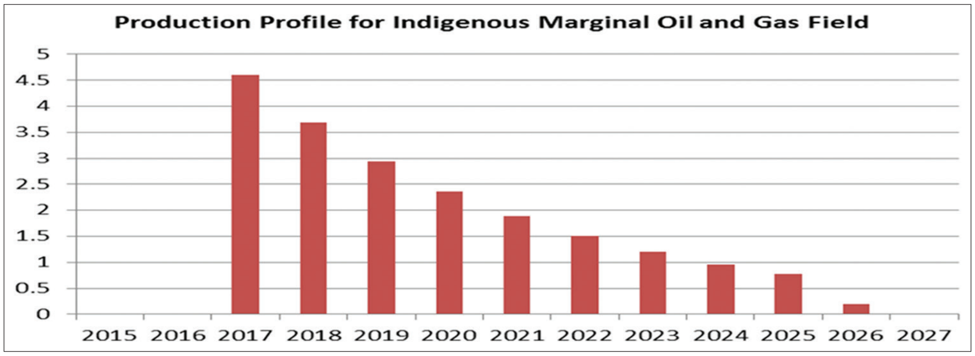
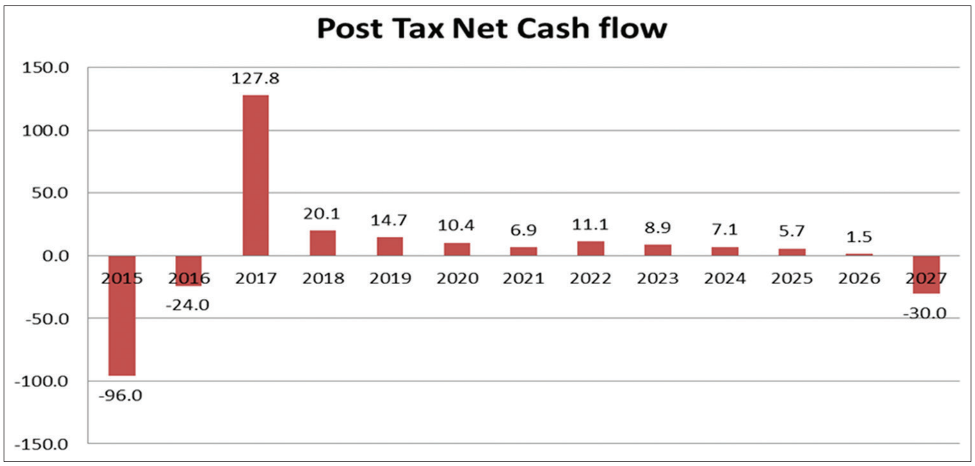


Figure 6: Yearly post-tax net cash flow for the hypothetical indigenous marginal field (in $million)



for the base scenario. Although this value falls short of the regular 0.30 which the IOCs usually adopt but it is relatively fair for the indigenous oil company which does not even have much portfolio to rationalise. While IRR on investment for the investor is 0.21, the "government take" is 89.4% for the base Scenario.

4.3. Effect of the Fiscal System and Economic Uncertainties on the Marginal Oil Field's NPV

This section shows the impact of some of the variables on the post-tax NPV of the indigenous marginal oil field's project. The input variables include oil price per barrel, development/capital cost, real discount rate, operating cost, abandonment cost, total field production, PPT and royalty. Henceforth, post-tax NPV will be referred to as NPV for the purpose of this study. All the results in this section were carried out on oracle crystal ball 11.1.2.3.500 version.

Figures 7, 8 and Table 4 show the effect of these input variables on the base scenario of the financial model built in this study. Figure 7 (Tornado chart) revealed that PPT, royalty and oil price have much impact on the field's NPV respectively. This is followed by devex/capex per barrel, real discount rate, total field production/recoverable reserves, opex per barrel and abandonment cost respectively. Tornado chart usually gives the oil firm a snapshot of the variable(s) to concentrate on more, so as to minimise the risk inherent in the project.

Figure 8 shows the spider diagram/chart which further depicts the effect of each parameter on NPV with the steepness of the slope. Curves with steep slopes either positive or negative, indicate that those variables have a large effect on the forecast, while curves that are almost horizontal have little or no effect on the forecast. The slopes of the lines also indicate whether a positive change in the variable has a positive or negative effect on the forecast. The Figure 8 shows that PPT, royalty, devex/opex, discount rate, opex and abandonment cost have negative relationship with the field's NPV, which means as each of these parameters increases, the firm's NPV decreases. On the other hand, oil price per barrel and total field production/recoverable reserves have positive relationship with the field's NPV. That is, as global oil price and total field production increase, the field's NPV also increases.

Table 4 shows that if the PPT (67.75%) increases by 20% and 40%, the marginal oil field will be rendered unviable as the NPV reduces from $29.32 million to −$41.63 million and −$112.59 million respectively, whereas the firm will make very good profit if the PPT reduces by 20% and 40% yielding NPV of $100.28 million and $171.23 million respectively.

An increase in royalty by 20% and 40% will reduce the field's NPV to $5.53 million and −$18.26 million respectively. So, 20% increase in royalty cannot make the field unviable but 40% increase will make the field unviable. If there is a reduction in royalty by 20% and 40%, the NPV for the field will increase to $53.11 million and $76.90 million respectively.

A reduction in crude oil price per barrel by 20% and 40% from the initial $60 per barrel reduces the NPV of the marginal field

Figure 7: Tornado chart measuring the parameters that most influence the marginal oil field's net present value (deviation of ± 40% using crystal ball)

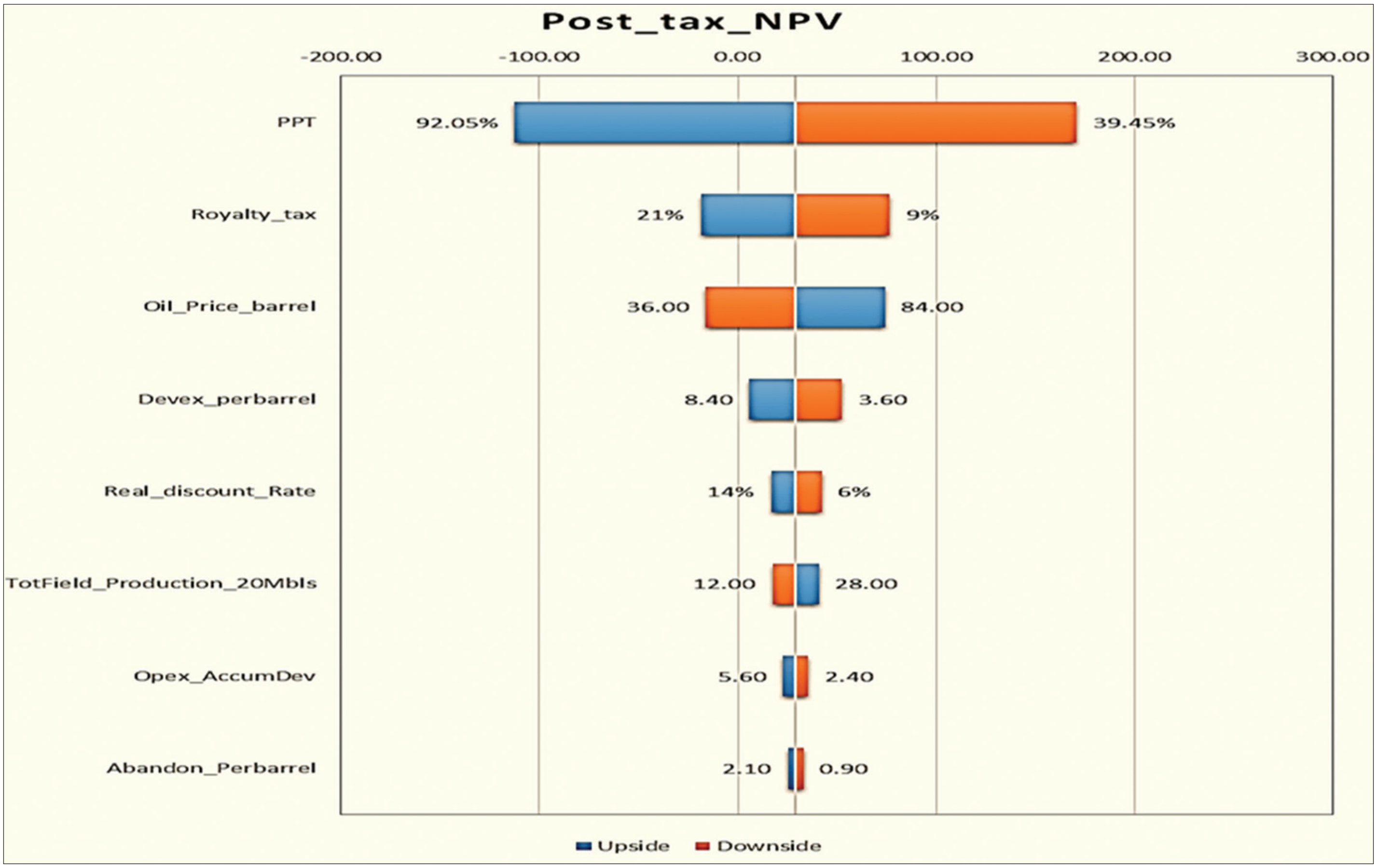
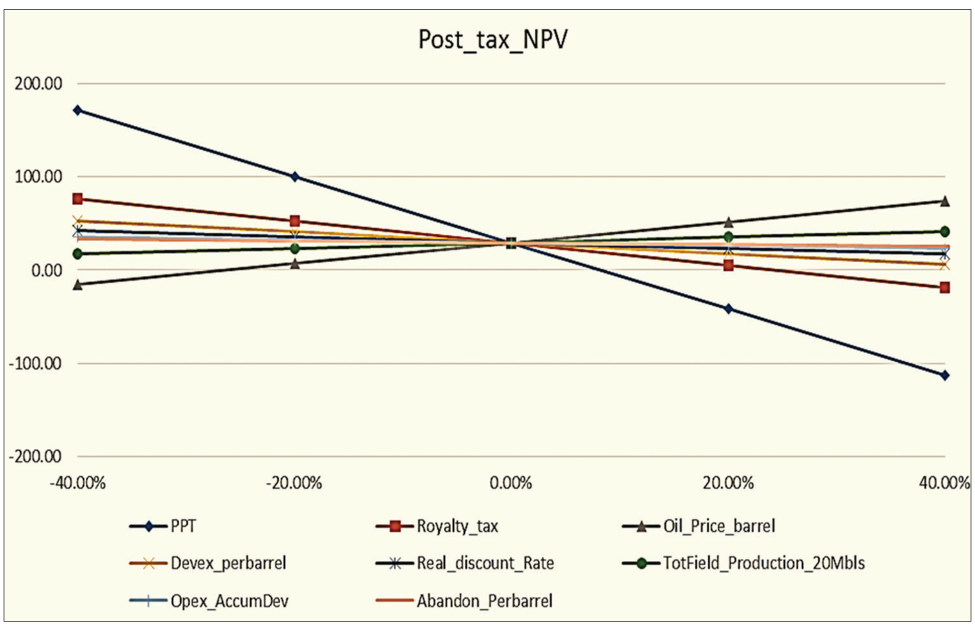


Figure 8: Spider chart measuring the effect of each parameter on field's net present value



to \$6.72 million and −\$15.88 million respectively. This indicates that if the crude oil price reduces to \$36 per barrel, then the field will become unviable as the NPV becomes negative. Meanwhile an increase in oil price per barrel by 20% and 40% increases the marginal field's profitability to \$51.92 million and \$74.52 million respectively. The result is in line with the study of Iledare (2004), Kaiser and Pulsipher (2004) which showed that while contractor take increases with an increase in price and profit oil, it falls with the increase in royalty and tax rate in Nigeria and Angola. Table 4 indicates that an increase or decrease of other parameters (capex,

Table 4: Effects of input parameters on post-tax NPV using oracle crystal ball

Input parameters	Elasticity*	Post-tax NPV (in million dollars)				
		−40%	−20%	0%	20%	40%
PPT	−5.93	171.23	100.28	29.32	−41.63	−112.5
RT	−5.1	76.9	53.11	29.32	5.53	−18.26
Oil price per barrel	4.51	−15.88	6.72	29.32	51.92	74.52
Devex/capex per barrel	−2.91	52.78	41.05	29.32	17.59	5.86
Real discount rate	−1.15	42.49	35.74	29.32	23.24	17.51
Total field production	1.00	17.59	23.46	29.32	35.19	41.05
Opex	−0.55	35.51	32.41	29.32	26.23	23.14
Abandonment cost	−0.33	33.15	31.23	29.32	27.41	25.5

*Elasticity is averaged across the entire test range, NPV: Net present value, PPT: Petroleum profit tax, RT: Royalty tax

real discount rate, total field production/recoverable reserves, operating cost and abandonment cost) by 40% though have different impacts on the marginal field's NPV but none of them renders this field unviable within the range of observation tested.

While PPT, royalty, devex/capex, real discount rate, opex and abandonment cost have negative elasticity of −5.93, −5.10, −2.91, −1.15, −0.55 and −0.33 with NPV respectively, the crude oil price and total field production/recoverable reserves have positive elasticity of 4.51 and 1.00 with NPV respectively. Thus, PPT, royalty and crude oil price are more elastic to the marginal field's NPV while abandonment cost is less elastic to the field's NPV.

4.4. Investment Hurdle Criteria for Marginal Oil and Gas Field Project

Oil and gas firms usually rank their project according to post-tax NPV/pre-tax investment ratio at 10% real discount rate otherwise known as economic hurdle rate of NPV/I (Kemp, 2011b). As a result of the marginality of the field considered in this financial economic modelling, this study adopted the economic hurdle rate of 0.2 (i.e., NPV/I ≥0.2). The investment hurdle rate of the marginal field for the base scenario was 0.24. Table 5 reveals that the marginal oil field project in this study did not pass the investment hurdle rate at 10% real discount rate when the PPT and royalty were increased by 10% and 20%; whereas the field passed the investment hurdle rate when there was a reduction in each of them by 10% and 20%. The marginal oil field also passed the investment hurdle rate of NPV/I ≥0.2 when there was an increase in crude oil price by 10% and 20% but did not pass the hurdle rate when there was a decrease in crude oil price by 10% and 20%. Meanwhile, the marginal field passed the investment hurdle rate when real discount rate was increased by 10% but did not pass when it was increased by 20%. However, the field passed the investment hurdle rate when the real discount rate was reduced by 10% and 20%.

4.5. Government Take on Marginal Oil and Gas Field Project

Government take which is the proportion of the project's profits captured by the host government was also measured. Government always want to maximise her take in the revenue generated from the oil and gas exploration as much as possible. However, if the government take is too high, it may dissuade the investors from investing. Table 6 shows that PPT, royalty and oil price impacted most on the government take of the marginal field under study.

Table 5: Impact of parameters on investment hurdle of marginal oil field using oracle crystal ball with deviations of ±20%

Input variable	Investment hurdle=Post-tax NPV/pre-tax investment					
	Elasticity*	−20%	−10%	0%	10%	20%
PPT	−12.22	0.84	0.54	0.24	−0.05	−0.35
RT	−5.65	0.44	0.34	0.24	0.15	0.05
Oil price per barrel	4.62	0.06	0.15	0.24	0.34	0.43
Real discount rate	−1.09	0.3	0.27	0.24	0.22	0.19

*Elasticity is averaged across the entire test range, PPT: Petroleum profit tax, RT: Royalty tax

Table 6: Impact of parameters on government take using oracle crystal ball

Input variable	Government take in present value term					
	Elasticity*	−20%	−10%	0%	10%	20%
PPT	0.75	75.99	82.68	89.38	96.07	102.76
RT	0.25	84.89	87.13	89.38	91.62	93.87
Crude oil price/barrel	−0.15	93.06	90.90	89.38	88.25	87.39
Devex/capex	0.10	87.72	88.52	89.38	90.31	91.31
Real discount rate	0.04	88.78	89.06	89.38	89.72	90.09
Opex	0.03	88.92	89.14	89.38	89.62	89.86
Abandonment cost	0.02	89.06	89.22	89.38	89.54	89.70
Total field production	0.00	89.38	89.38	89.38	89.38	89.38

*Elasticity is averaged across the entire test range, PPT: Petroleum profit tax, RT: Royalty tax

Government take tends to increase as crude oil price reduces which is not good for the profitability of the field. This implies that government will earn more from this field when crude oil price plummets and will earn less when the crude oil price rises. Although the level of sensitivity of government take to crude oil price is low, but this may impair investment when the price of oil falls to a greater extent. This was also noticed by the study conducted by Kemp (1992) where fiscal system in Norway and Netherlands produces a significantly high level of take, with little incentives for small fields and the system was regressive at 10% real discount rate in PV terms.

4.6. Monte Carlo Simulations of Marginal Oil Field Project

For this study, crystal ball simulation sampled 10,000 trials for the model that was used. The model considered the Monte Carlo simulation taking the standard normal distribution of the random variable of the discount factor. Figure 9 shows that the EMV of the marginal oil field was $29.56 million with an error value of

±\$0.06 million. The model further revealed that the marginal oil field is viable to develop by the indigenous player after considering the information of the inherent risks and uncertainties relating to the development of such field at the present period. The standard deviation of 6.24% showed that the extent of risks in the model is low. This probabilistic approach has an advantage over deterministic approach that uses a single point solution and would not show how optimistic or pessimistic the results might be (Charnes, 2007).

4.7. Other Economic and Social Issues Affecting Marginal oil and Gas Field Project

Further information was also obtained from the oil and gas workers across the indigenous oil firms. A total of 84 respondents out of 120 appropriately filled the questionnaire that was administered. Table 7 shows the perception of the oil and gas respondents on other economic and social issues that could be affecting the development of marginal oil and gas field. The table revealed the result of the ordered scale which ranges from strongly disagree to strongly agree. Majority (52.3%) of the respondents disagreed that Nigerian tax system encourages marginal oil and gas field development while few (29.8%) of the respondents agreed that Nigerian tax system encourages marginal field development. Also, most (61.6%) of the respondents disagreed that the Nigerian fiscal system on marginal field is stable and neutral. Furthermore, 65.1% of the respondents believed that the government take on the marginal field is too much and may affect the continuous

Figure 9: Monte Carlo simulation result of marginal oil field for the model

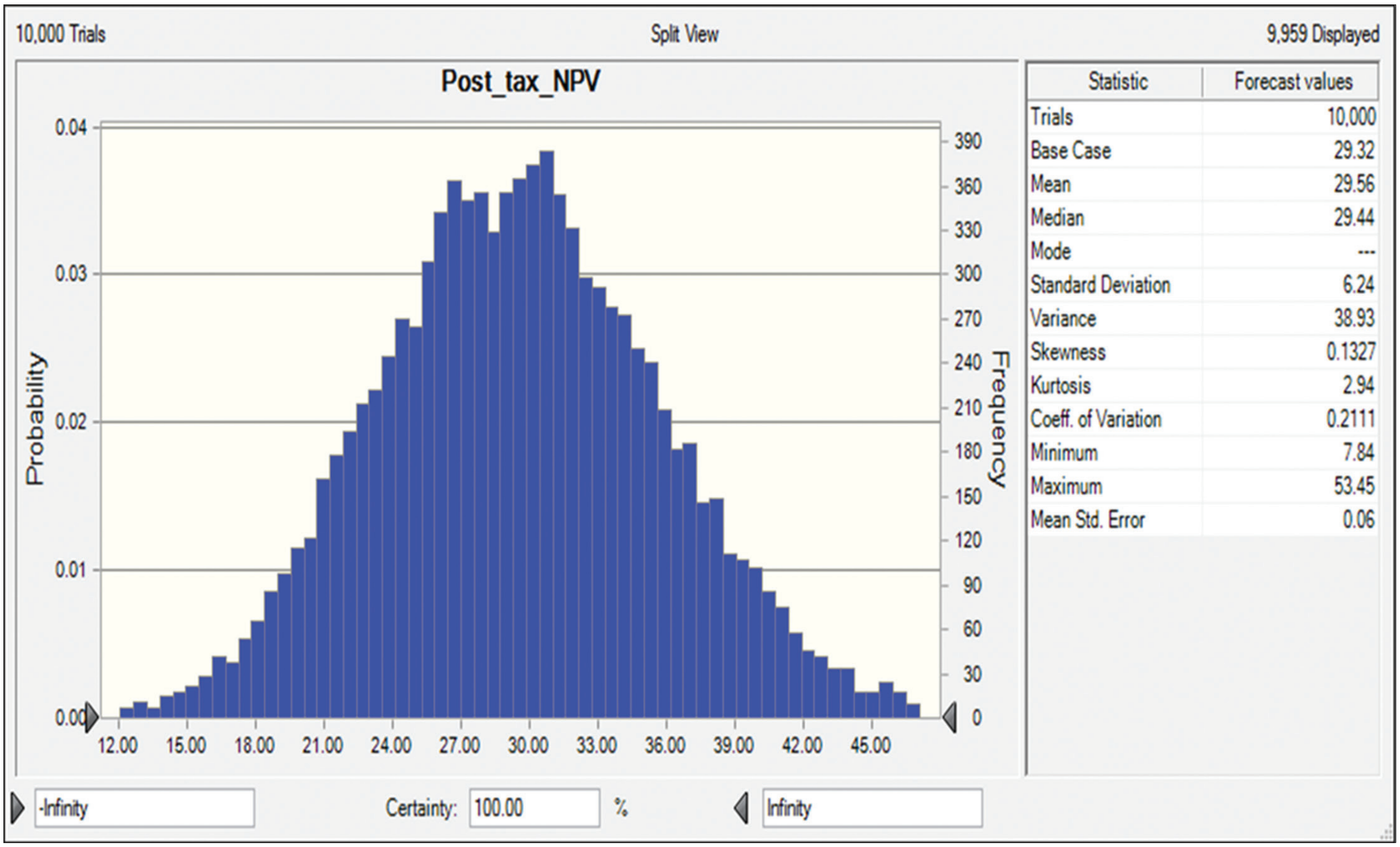


Table 7: Other economic and social issues affecting marginal oil field development

Issues	Strongly disagree (%)	Disagree (%)	Agree (%)	Strongly agree (%)
Nigerian tax system encourages marginal field development	16.7	52.3	29.8	1.2
The fiscal system is stable and neutral	15	61.6	15.1	8.3
Nigerian government take is too much and affect investment	1.2	20.9	65.1	12.8
There is need to reduce tax on marginal fields for them to become more viable	-	5.8	70.9	23.3
The tax on marginal fields is perfect as it is	31.4	58.1	10.5	-
Fund and financial issues play a dominant role in marginal field development	-	3.2	35.2	61.6
Oil theft and pipeline vandalism pose a big threat to marginal field development	-	6.0	70.8	23.3
Oil spills contamination of soil, surface and ground water	-	24.4	55.8	19.8
Social unrests and high demands of those living in the immediate community	-	5.8	69.8	24.4

Source: Authors' Survey (2015)

development of such oil and gas field. Majority of the respondents also agreed (70.9%) and strongly agreed (23.3%) that there is need to reduce tax on marginal field for them to become more viable to develop. 58.1% and 31.4% of the oil and gas respondents correspondingly disagreed and strongly disagreed respectively that the tax on marginal field is perfect as it is. Most of the respondents also perceived that funds and financial issues play critical role in the development of marginal oil fields with 61.6% strongly agreed and 35.2% agreed. The respondents agreed that social issues such as oil theft and pipeline vandalism (70.8%), oil spills contamination (55.85), and social unrests and high demands of those living in the immediate community (69.8%) affect the development of marginal oil and gas field development.

5. CONCLUSION AND RECOMMENDATION

The study assessed the economic factors influencing marginal oil and gas field development by the indigenous oil firms in Nigeria. The focus of the study was centred on the indigenous oil firms considering the nature of the oil field which the IOCs have abandoned for mainly economic reason. The fields have been considered marginal for the IOCs since there overhead expense is huge in exploring such fields. The study shows the phases involve in developing marginal field as well as the economic and fiscal uncertainties facing the indigenous marginal field operators. Using Monte Carlo simulation analysis, the study revealed that the hypothetical marginal oil field considered in this study generates $29.32 million and $29.56 million as post tax NPV and EMV respectively. This indicates that the hypothetical marginal oil field project considered in this study is viable under the base scenario since the value of post-tax NPV and EMV are greater than zero. The investment hurdle rate (NPV/I) is 0.24 which is above 0.20 taken for the marginal oil field project, and the IRR on the project for the investor is 0.21. Also, the "government take" is 89.4% for the base Scenario.

When the marginal field was subjected to further sensitivity, the result revealed that PPT, royalty, crude oil price, capex and opex have more effect on the field's NPV respectively. An increase in PPT and Royalty could affect the viability of the field, and decrease in crude oil price to $35 could also affect the viability of the field. Furthermore, the study noticed a regressive nature of the fiscal system which was evidenced as government take increases when the crude oil price decreases for the marginal field project. The study also revealed that non availability of fund for the indigenous operators from Nigeria's banks, high government take and oil thefts among others posed a big challenge to marginal field development. The study therefore suggests certain recommendations for the policy makers in Nigeria.

Firstly, Nigerian Government should periodically re-assess the impact of her petroleum fiscal system and adjust the relevant parameters as needed so that the fiscal regime application to future marginal oil field projects reflects changes in market conditions, government policy and geological risks to ensure efficient use of resources. Secondly, government should also provide more allowances for the indigenous marginal field operators such as strategies used by some oil rich countries to encourage the indigenous marginal field operators; for example, ring fenced expenditure supplement used in UKCS, resource rent tax in Australia and Brown Tax in Norway. Lastly, Government through Central Bank of Nigeria should encourage the commercial banks to give credit and financial support to the indigenous oil and gas firms. This may be in form of interest rate concessions and less stringent documentations avail to the indigenous firms.

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