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INVESTMENT ANALYSIS OF MARGINAL FIELDS' DEVELOPMENT IN NIGERIA USING REAL OPTIONS APPROACH

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Abstract

Marginal fields (MFs) are economically sensitive, and investments in them are very challenging. Literature abound on the use of traditional financial models to evaluate investment analysis of MFs. However, none of these captures unexpected market developments and changing conditions. Therefore, this study investigates the investment analysis of MFs using Real Options Approach (ROA) with emphasis on uncertainties, flexibilities, and their values in Nigeria. The Traditional financial model was modified by incorporating three new uncertainty variables captured under Niger Delta militant insurgencies [cost of repairing /replacing vandalised facilities (CR), ransom paid to kidnappers (RP), and total revenue lost resulting from annual shut-down (AS)]. The model was validated using secondary and primary data from producing MFs. Sensitivity analysis was conducted to identify the impact of key uncertainty variables. Three approaches of ROA, Deferral Option (DO), Abandonment Option (AO) and Expansion Option (EO), were also employed to evaluate the profitability of both projects. The values of Net Present Value (NPV), Internal Rate of Return and Payback Period confirmed investment profits for offshore and onshore MFs projects. Result showed that Oil price was the most sensitive on *the offshore's NPV, while the Gas price had the most effect on the onshore's NPV. The AS was the most sensitive among the insurgency variables for both projects. Additional values on investment were obtained from ROA approaches relative to the NPV valuation. In conclusion, decision making in marginal fields' investment is more guided using real options approach as it is more exploratory and informative than the traditional financial models.*

Keywords: Marginal fields investment analysis, Real options approach, Traditional financial models

INTRODUCTION

Statement of Problem

As larger fields become exhausted, countries across the world are finding an alternative production model to maximise their energy resource endowments by exploiting viable alternative solutions in small or secluded fields (ABT oil and gas, 2014). This was why in 2003, The Federal Government of Nigeria awarded 30 marginal fields out of the available 183 in order to grow more reserves of petroleum assets and encourage the participation of local companies in the upstream sector. This development was hinged on the local content initiative of the Federal Government of Nigeria whose main objectives are the involvement of local companies in the upstream sector of the petroleum industry towards a higher level of indigenisation, and growing more reserves of petroleum assets (Idigbe and Bello, 2013).

Reports (for example, Uche, 2011; Chijioke, 2013; Osaneku, 2013; Idigbe and Bello, 2013; Eboh and Obasi, 2014; Adeogun and Iledare, 2015; Ashore, 2015; Ekeh and Asekomeh, 2015 and Akinwale and Akinbami, 2016) reveal that Nigeria has a enormous reservoir of marginal fields, predictably put at over 2.3 billion barrels of Stock Tank Oil Initially in Place (STOIIP) spread over 183 marginal fields'. Exploring these marginal fields would increase the country's daily production of oil. However, regardless of this commendable marginal fields' policy, the success and the involvement of the indigenous explorers in the field are still marginal because, only few have made significant progress in producing from the fields, after its initiation in the year 2003. According to the 2015 financial statement of the Nigerian National petroleum Corporation, marginal fields only contributed about 3%, while the Production Sharing Contract (PSC), Independent and Sole risks, Alternative Funding – Joint Venture (AF-JV) and Joint Venture (JV) contributed 42%, 7%, 16%, 32% respectively to the total crude oil production in Nigeria. This has been attributed to various challenges that marginal fields' investors did not envisage and properly planned for (Awotiku, 2011).Presently, only 12 out of the 30 marginal fields (that is 40%) have taken their fields' to the first oil production, which is not in accordance with the desired pace of the federal government initiative. These necessitated the conduct of empirical studies to investigate what could be responsible for the slow pace of the marginal oil and gas fields' development by the indigenous oil companies in Nigeria.

A number of studies have investigated the marginal oil fields development in Nigeria and issues covered included the status, constraints, challenges and prospects of marginal fields; Uche, 2011; Chijioke, 2013; Osaneku, 2013; Idigbe and Bello, 2013; Eboh and Obasi, 2014; Adeogun and Iledare, 2015; Ashore, 2015; Ekeh and Asekomeh, 2015 and Akinwale and Akinbami, 2016. These studies highlighted some of the challenges the marginal oil field operators faced. Such as, legislative and policy bottlenecks, delay in the government approval process of marginal fields' award, uncertainty of assistance from foreign equity partners and local investors, unfavourable tax regimes and multiple taxation, inadequacies in local content development policy, oil price volatility, delay in delivery of finance services from financial institutions, continuous community disturbances, increased asset vandalisation and illegal refining of crude oil.

Investors that the Nigerian marginal fields were awarded to seemingly have not identified all the associated risks; hence, difficulty in moving from bid winning to field development. Some of the identified risks include: Technical Risks: (that is existing well not having technical integrity/casing integrity), low reserves and militant insurgencies.

Some other risks that were however, made known to the companies from documents and information provided prior to bidding process include: High Gas- Oil Ratio (GOR), the total numbers of existing wells drilled and the total number of fields with reserves and nearness to existing facilities in order to transport or store the crude oil or gas.

Managers are faced with different uncertainties in nearly every aspect of their decisions (Janney and Dess, 2004) and most investors do not fully realise the unbelievable stress the industry is under, and the risk factors affecting the oil and gas sector (Energy Digital, 2011). To guarantee the success of a project, it is of utmost importance for the manager to find ways of handling risks and uncertainties that can pose possible risks before and after the project. This led to the research questions that this thesis addressed:

1. In the midst of various uncertainties like oil price volatility, militant insurgency, amongst others, can marginal fields' investment be profitable in Nigeria?
2. What are the key uncertainty variables that can affect the profitability of the marginal fields' development?

3. How can the applicability of Real Option Approach (ROA) be an active management tool in deciding when to defer, abandon or expand a project in the midst of various uncertainties?

Research Objectives

The primary objective of this study is to analyse the investment decisions in marginal fields' development in Nigeria using Real Options Approach.

The specific objectives are to:

I. Modify an existing Discounted Cash Flow (DCF) model by incorporating new uncertainty variables in order to obtain the Net Present Value (NPV), Internal Rate of Return (IRR) and Payback Period (PP) for the marginal fields' development.
II. Evaluate the effect of various risks and uncertainties on the Net Present Value, Internal Rate of Return and Payback Period using sensitivity analysis.
III. Show the applicability of Real Options Approach in some selected marginal fields' in Nigeria via options to defer, abandon or expand at anytime, during the relinquishment requirement period.

Justification for the Study

Economic analysis is an essential part of every field development, as it is the pivot on which several other decisions revolve, and also helps to identify the best investment opportunities in terms of cost, revenue and risk mitigation (Awotiku, 2011). Many empirical studies like: (Abisoye, 2001; Awotiku, 2011; Uche, 2011; Chijioke, 2013; Adamu*et al*., 2013;Osaneku, 2013; Idigbe and Bello, 2013; Eboh and Obasi, 2014; Adeogun and Iledare, 2015; Ashore, 2015; Ekeh and Asekomeh, 2015 and Akinwale and Akinbami, 2016) have used different evaluation models such as, Discounted Cash Flow (DCF) analysis via Net Present Value (NPV), Internal Rate of Return (IRR), Payback Period (PP), Profitability Index (PI) and undiscounted profit to investment ratio to assess the economic viability of developing fields.

After reviewing various related literature, this study admits that The NPV only takes into consideration the likely outcomes required for the development. It does not account for the changing conditions, new information and flexibility that are open to the operator after the initial go or no go project decision must have been taken. Hence the NPV is static and if initial evaluations lead to a negative NPV, the suggestion would be that the field development does not continue (MacLean, 2005). For instance, managers can increase the size of a production operation in response to increase in unexpected demand, or cut funding for a research project that is not discovering marketable products. This flexibility has a value that is not captured by the traditional DCF approach (Damodaran, 2003; Kodukula, 2006; Abisoye, 2007; Bowman and Moskowitz, 2011; Acheampong, 2010; Pire et al., 2012).Therefore, using such techniques to evaluate the development of marginal fields' project does not show any benefit in the economics of the field development model (MacLea, 2005).

For the purpose of this research, more literatures were reviewed to ascertain the best model or option that will incorporate future uncertainties plus flexibilities values and weighs the options available to guide investment decisions in the marginal fields' development.

The use of Real Option analysis was considered as an evaluation model in the investment analysis of marginal fields development because it adds more value to the evaluation process of oil field developments compared to traditional methods of making investment decisions. Since real options, incorporates the value of flexibility to projects, upfront capital expenditure can be saved if the project is considered not viable (Abisoye, 2001, Acheampong, 2010).

A visual illustration of effect of flexibility on a project value is shown in figure 1.

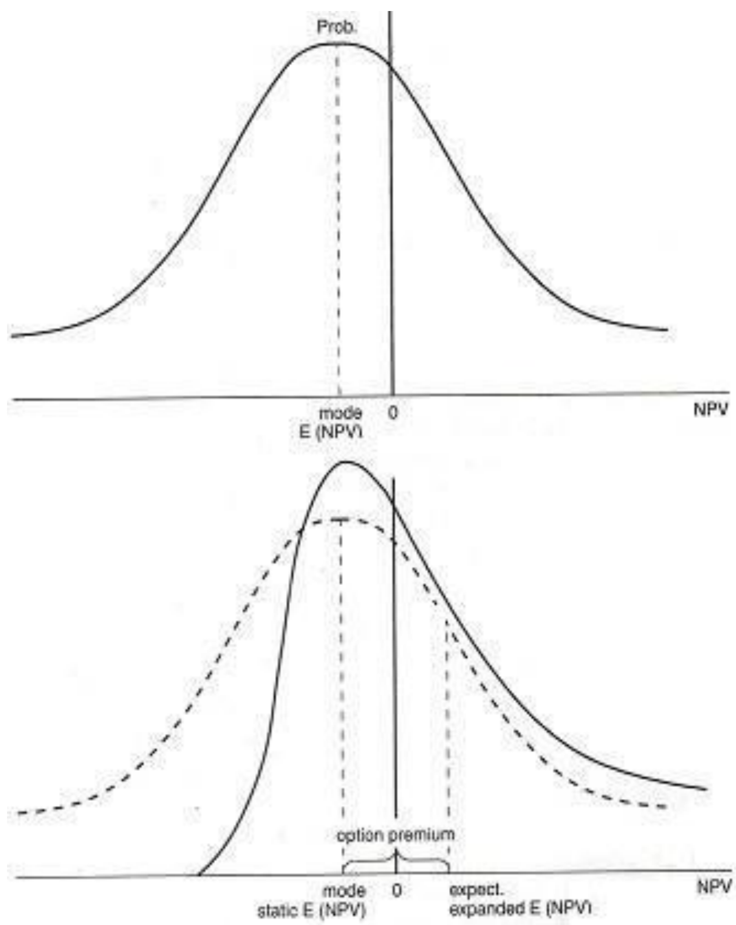


Figure 1: Project value with and without real options
Source: Trigeorgis, 1996, p. 123

Figure 1 demonstrates that the effect of flexibility of real options is a probability distribution of the project value skewed. The downside loss is limited by the options, and the upside potential gain is improved. This skewness opposes the symmetric probability distribution under passive management presented by the traditional NPV. In other words, options provide adapting tools to react to future events different from those incorporated in the expected NPV analysis (Thuesen and Carlsen, 2015).

BACKGROUND OF THE STUDY

Oil and Gas Exploration and Production in Nigeria

Table 1 Snapshot of the History of Oil& Gas Exploration in Nigeria

YEAR	HAPPENINGS
1907	The search for oil deposits started in Nigeria
1914	Efforts ended because of the outbreak of World War I
1923	After the World War I license was given to the D'Arcy Exploration Company and White Hall Petroleum. Neither of them found oil in commercial quantity so the license was returned
1937	Exploration began again. Shell and British Petroleum (Shell D'Archy) were granted the sole concessionary right over the whole country. They enjoyed a monopoly of exploration
1939-1945	Activities were terminated by world war II (WWII)
1946	Exploration wells were drilled by Shell after WWII
1951	1st test well was drilled in Owerri Area
1953	Oil was discovered in non commercial quantities
1956	1st commercial oil was discovered in an Olobiri field in the Niger Delta
1958	Second Oil discovery at Afam & the giant Bomu oil field/ First shipment of oil from Nigeria
1960s	Petroleum Sector Started playing a vital role in the economy and a total of 847,000 tonnes of crude oil was exported
1962	Elf and Nigeria Agip Oil company started operations in Nigeria
1963	The Ubata gas field was discovered by Elf and started their first production
1968	Mobil Producing Nigeria Limited was formed
1971	Nigeria joined the Oil producing, exporting countries
1970	Department of Petroleum Resources (DPR) Inspectorate started/ Mobil and Agip started production
1973	First Participation Agreement; Federal Government acquires 35% shares in the oil companies

Table 1...

1974	Second Participation Agreement, Federal Government increases equity to 55%
1975	DPR upgraded to Ministry of Petroleum Resources
1977	NNPC was established by the Government
1979	Third participation Agreement; NNPC increases equity to 60%, Fourth Participation Agreement; BP's shareholding nationalized, leaving NNPC with 80% equity and shell 20% in the joint venture
1984	The Agreement consolidates NNPC/ Shell joint venture
1989	Fifth participation; (NNPC=60%, shell, 30%, Elf=5%, Agip=5%
1993	Production Sharing Contract signed –SNEPCO/ Sixth Participation Agreement (NNPC=55%, Shell=30%, Elf=10%, Agip=5%)
1995	SNEPCO starts drilling first exploration well/ NLNG's Final Investment Decision taken
1999	NLNG's first shipment of Gas out of Bonny Terminal
2000	NPDC/NAOC Service Contract signed
2002	A New PSCs agreement signed/ Liberalisation of the downstream sector/NNPC commenced a retail scheme

Source: Nigeria Oil and Gas Forum, 2013

Overview of Marginal Fields' Development in Nigeria

Marginal fields refer to discoveries which have not been exploited for long, due to one or more of the following factors:

i. Very small sizes of reserves/pool to the extent of not being economically viable.
ii. Lack of infrastructure in the vicinities.
iii. Prohibitive development costs, fiscal levies and technological constraints.

However, should technical or economic condition change; such fields may become commercial fields.

Marginal Field was defined as, any oil discovery whose production would, for whatever reasons fail to match the desired or established rates-of-return of the leaseholder(Egbogah ,2011). Based on the data gotten from the Nigerian National Petroleum Corporation (NNPC) on oil and gas activities for the year 2015the marginal fields' operators produced 23.3 million barrels of crude oil, indicating a daily average of 63,812 barrels in 2015. This is against a total of 773.5 million barrels produced by all the operations in the sector in the year 2015 (Figure 2). This translates to an average daily crude oil production of 2,119,064 barrels, showing that the marginal fields' operators are yet to make a worthy impact on Nigeria's petroleum sector (NNPC Annual Statistical Bulletin, 2015), (See Figure 2 for illustration). This simply indicates that marginal fields' still has a total reserve of about 2.2 billion STOIP.

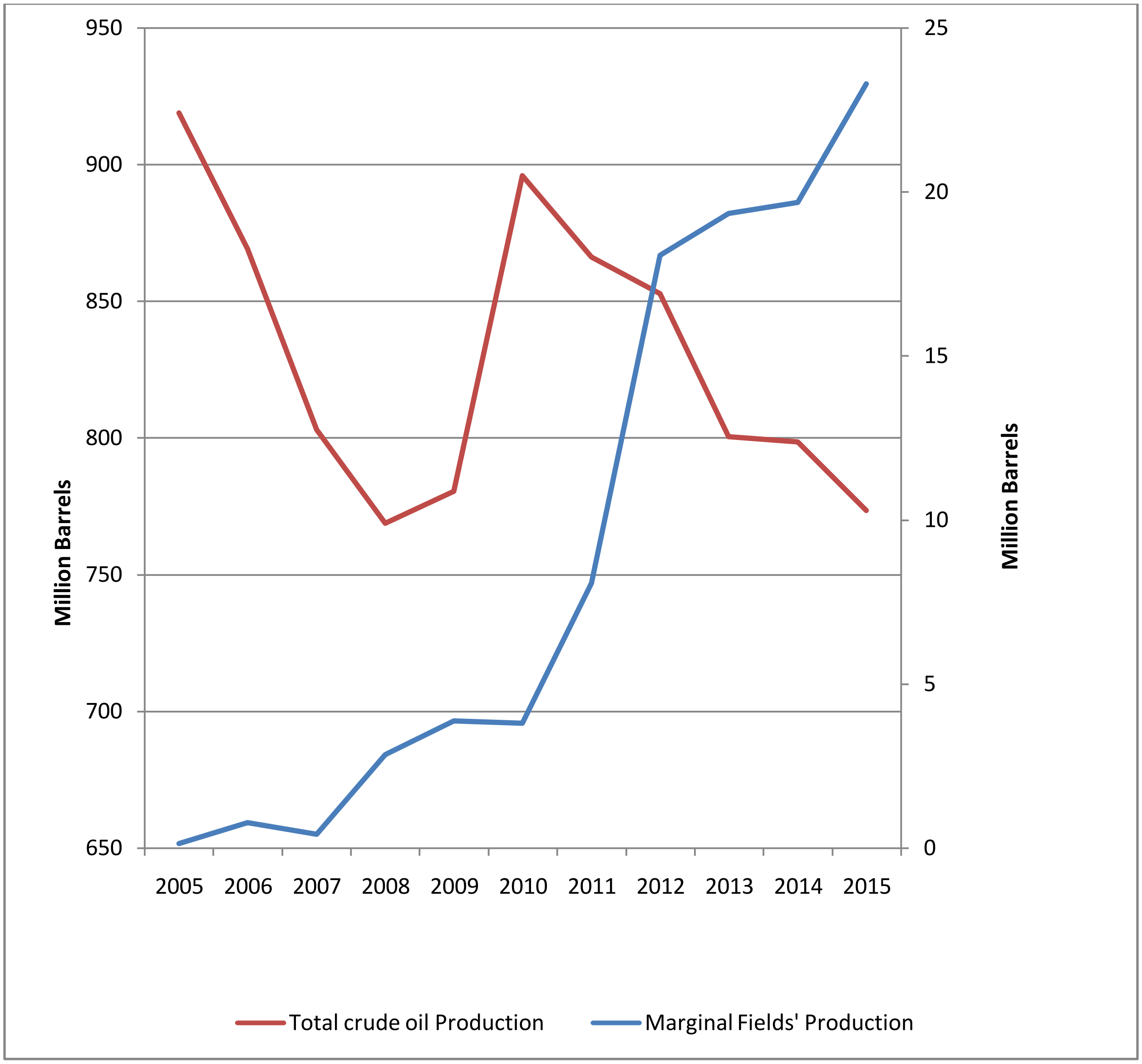


Figure 2: Historical Trends of Total Crude Oil Production and Marginal Fields Production in Nigeria (2005-2015)

Source: NNPC Statistical Annual Bulletin, 2015

LITERATURE REVIEW

Overview of Marginal Fields' Development

Goldsmith (1995) examined the analysis of the economic effects of new and small marginal oil fields in Alaska covering a twenty year production life. The analysis was based on existing information about the public sector and the economy combined with a hypothetical marginal oil field. Some of the inputs used to develop the parameters for the analysis findings came from an ongoing study of the Badam oil. The result of the study showed that revenues generated from the marginal field exceeded the costs to state government in all cases except the low price, low royalty and the low production case when they are equal. Of the five sources of revenues identified, royalties, potential personal taxes and the pipeline effect contributed most to revenue while the corporate income tax and statewide property tax had little contribution to revenue. Therefore it was concluded that marginal oil field development in Alaska can generate jobs and income for workers and increase the state's tax base and sales for Alaska businesses

Furthermore, Awady (2001) investigated marginal field development in the western desert of Egypt. The development plan, reservoir faces, the use of suitable technology, and economic indicators for small fields which were operated and managed by Agiba in the Qattara Depression were analysed. The study showed that operating and capital costs were highly reduced for the considered field. The research concluded that;

1. Development of Marginal Fields requires flexible and innovative management approaches that involve:
   i. Operations phasing.
   ii. Flexibility in the development plan to accommodate changes.
   iii. Suitable technology that suits the particular condition of the fields.
   iv. Nearby fields should consider sharing of available facilities to improve the economic worth of smaller reserves.
2. It is possible to develop fields with reserves less than 5million barrels in harsh conditions in an economic manner

Ayodele and Frimpong (2005) carried out a detailed economic analysis to assess the feasibility of a contractual agreement of a proposed marginal oil field in Nigeria. The economic analysis involved cash flow modelling, project profitability analysis, project sensitivity analysis and risk modelling. Results showed that investing in the development of Nigerian marginal oil fields is worthwhile. The result also showed that the proposed agreement leads to a favourable Return on Investment for all parties involved. The project's sensitivity analysis showed that if the combined cost of seismic survey and signature bonus is increased beyond 10%, the project becomes uneconomical. If the price of oil falls below US$18.07, the projects need to be re-evaluated because the discounted payback period will exceed the expected project life. Risk analysis showed that as NPV increases, so also the risk level associated with such NPV increases too.

Akinpelu and Omole (2009) examined the economics of Marginal Field Development. NNPC 2012 fiscal / regulatory terms were used to identify the most significant variables impacting the economics. The production variable was treated as one of the main uncertain variables in the probabilistic model because Nigerian Oil and Economic models are usually production dominated. It was stated that the main reason why many marginal fields do not make it into development stage in the budget allocation process is economic. Results showed that the field decline rate and initial well productivities, Exploration and Development well costs have a significant impact on marginal fields Economics. They recommended that future research should not just limit the variables to production and the well costs variables. Other costs like jackets and flow line investment, barge costs and operating costs should be included in the cost management strategy.

Nischal *et al*. (2012) analysed the potential of offshore marginal fields in India. The Oil and Natural Gas Corporation (ONGC), India, was considered as the case study. The ONGC had more than 165 marginal fields with a total reserve of more than 297MMT. Most of the reserves were far away from existing infrastructures. Development on a stand-alone basis could not be considered because of their location at a great water depth or some even had insufficient reserves. Several efforts and integration of advanced technologies and human resources to make the fields economically feasible became abortive. This made the ONGC to monetise 53 fields while 69 other fields are still under various stages of monetisation. Nischal *et al*. (2012) illustrated through case histories the approach of the offshore marginal fields' with specific emphasis on Economic marginal fields grouping, CAPEX reduction through hired FPSO e.t.c. Due to these initiatives, production is expected to peak at about 125,000bopd and gas production will also peak at about 17Mm^3/d in 2014-2015. Also, ONGC early monetisation made its marginal field's oil production to rise to 26,000 barrels per day and gas production of about 4MMSCMD.

Adamu *et al*. (2013) provided a perspective on diversification, investment and resource development on offshore marginal field in Nigeria. A number of parameters were employed to carry out economic analysis for project profitability, cash flow modelling and sensitivity analysis. The economic parameters employed include Net Present Value (NPV), Internal Rate of Return (IRR), Present Value Rate (PVR), Pay Back Period and Profit to Investment Ratio (PIR). Probabilistically, the certainty of having a positive NPV and good IRR values far above the hurdle rate for investment in Nigeria was achieved. The sensitivity analysis showed that oil price and tax rate are key sensitive parameters in maximising profit. The result also indicated that the development of offshore marginal fields in the Niger Delta of Nigeria is economically viable.

Ezemonye and Clement (2013) provided insight on the inherent risks, discussed their implications and validation for their economic importance and implications of Marginal Fields in Nigeria between 2010 and 2012. A survey approach involving the use of Principal Component Analysis (PCA) was employed. They identified 53 risk variables. The PCA was successful in helping to reduce the data to 12 risk clusters that are appropriate to Nigeria's marginal fields namely: Kernel of risk concentration, comprising of 13 variables (e.g. Recovery rate, financial and economic constraint operating costs of marginal fields, oilfield size, etc.), Socioeconomic and techno- political risks (e.g. exchange rates, operational risks, interest rates), Reservoir uncertainty risks (e.g. marginality of the reserves), Reservoir Voluminousity (e.g. formation stock tank), Barriers (e.g. reservoir damage, obstruction of the International Oil Companies), Operational and Chancified risks (e.g. logistics), Security and returns risks (e.g. spot market price), Yield and operational risks (e.g. market demands), Well production management (e.g. statistical prediction risk), Wildcat risks syndrome (e.g. dry hole) and Ancillary costs risk (e.g. resources cost volatility). The authors confirmed that risk sneak about in uncertainty and if not properly planned for will affect the profitability of the project therefore needs pre-emptive measures.

Idigbe and Bello (2013) investigated the challenges that confront the local operators and basic roles that will improve the contribution of Marginal fields in Nigeria towards value creation. The paper presents the opportunities to sustain social and economic responsibilities. It was gathered that the monetisation of natural gas assets and proper business engineering in the marginal fields' will be best practices for value creation and also have a significant impact on the sustainable operations of the fields. This will guarantee the success of the marginal field initiative, specifically, in the growing of natural gas reserves, a key component for power generation in Nigeria.

Adeogun and Iledare (2015) argued that the notion to develop marginal oilfields as a means of increasing oil and gas reserves in Nigeria has not been well defined since inception. The paper redefines the concept of marginal oilfields in terms of concrete and measurable terms, keeping in consideration recoverable reserves, prevailing fiscal terms and economic conditions. A comprehensive economic analysis was carried out. A deterministic model was used to determine the profitability of the field and a stochastic model was used to analyse possible scenarios as changes occur in certain input variables with the corresponding output. Results showed that marginal fields are considered a worthwhile investment if adequate incentives are granted by the government. For example, if a downward review of signature bonus had little or no impact on the rate of return of investment while reduction in royalty and petroleum profit tax has a positive impact on investment which will make investment in marginal fields more rewarding for investors. Oil Price was considered to be the major driver of the profitability of the project.

Ashore (2015) addressed the economics of investment matrix for marginal fields' development in Nigeria. The marginal field considered in the study had a negative NPV due to fall in oil price as the field was producing from a new facility. But results show a positive NPV when produced from an already existing field. The result also showed that operating and capital expenditure were too high for the marginal field and so reduced their profitability.

Ekeh and Asekomeh (2015) carried out an optimality test on an onshore and offshore marginal field development financing arrangements in Nigeria. Because of the financial challenges faced by many Marginal field operators, some of them resorted to partner with some foreign investors to carry their share of development costs. The discounted cash flow was used to analyse the economic viability of the marginal fields. Four different scenarios were considered; Marginal fields' sole risk, Foreign Partner sole risk, joint venture without the foreign partner carrying the development cost and joint venture with the foreign venture carrying part of the development cost. Empirical results appear to imply that marginal fields' operators are better off if they can contribute their share of the development costs by sourcing for funds domestically than when they are carried fully by a foreign partner. The NPV analysis confirmed that carrying of interest favours the foreign partners over the marginal fields in a joint venture arrangement. In addition, oil price and petroleum profit tax are considered to have the greatest impact on the NPV in both models.

Xochipa and Galicia (2015) presented a business case that can compete for investments to meet the requirements of profitability and contribute to the goal of producing the project. The study used a two stage methodology. The first stage was used to consider the individual assessment of the fields'. While the second stage was the search for alliance to review opportunities for production called MEAPTECH meaning 'Methodology for investment projects applying technical, finance and business levers. Business cases for three different fields in the Gulf of Mexico were identified and improved with attractive capital efficiency. From the three fields, CrudoLigero Marino project has competitive economic indicators to request financial resources and initiate the development of the other fields.

Akinwale and Akinbami (2016) carried out the economic evaluation of Marginal oil fields using financial simulation. Fiscal regime and economic factors that could be hindering oil field development among the indigenous oil firms were considered in their analysis. Result showed that marginal oil field's project is viable with post-tax NPV. Petroleum Profit Tax, Royalty and crude oil price have more impact on the NPV. It was recommended that a periodic assessment of the fiscal regime and appropriate policy by the government to encourage the local players in developing the marginal oil field.

Humphrey and Dosunmu (2016) examined the success factors underlying the development of marginal field by Niger Delta Exploration and Production Company in Nigeria. An extensive literature review on marginal oil fields was carried out in order to give explanation of the success of marginal fields' development using Ogbelle as the case study. Humphry and

Dosunmu's study reveals three explanations that are relevant to the success story: The know-how developed by the Niger Delta Exploration and production company through collaboration with third parties, Risk management among which are the formation of partnership, and joint venture and effective monetization of natural gas and the role of capital market in funds raising which helps in the development of marginal field project. The critical success factors for Ogbelle field development were identified as: Risk management through the formation of partnership, effective utilisation of natural, collaboration with third party and the role of stock market was their major conclusion.

Empirical and Methodological Review of Real Options Analysis in the Oil and Gas Industry Using Binomial Lattice

Lund (1999) considered an offshore field development by using a case from the North Sea field Heidrun in Norway. The author used a stochastic dynamic programming model for project evaluation under uncertainty taking into account the uncertainty in oil price, reservoir size and well rates. The study modelled the price as a geometric Brownian motion, and used a binomial valuation model to find the optimal size of the production rig and investment timing. Results from the case study revealed a significant value of flexibility, and clearly illustrated the shortcoming of today's common evaluation methods. Particularly capacity, flexibility should not be neglected in future development projects where uncertainty surrounding the reservoir properties is substantial.

Abisoye (2007) investigated how Real Options analysis and decision analysis can maximise the returns on a given project and minimise the losses. The analysis focused on the option to change the scale of a project. The study used a sample and the Rother field as a case study. The results of the Rother options analysis showed the optimal field development strategy given the various reserves expectations. It was concluded that the use of Real Option analysis can add more value to oil field developments compared to traditional methods of making investment decisions. Since real options, add flexibility to projects, it can save upfront capital expenditure.

Junior *et al*. (2007) presented the valuation of a hypothetical onshore mature oil field using the real option approach. Their research was based on the new bidding rounds organised by the Brazilian Petroleum Agency in 2005. A discrete- time approach and a binomial decision tree with risk – neutral probabilities on Copeland and Antikarov (2001) were considered to obtain the project value. The research pointed out how a project can be evaluated, considering that the high volatility of the oil prices and the flexibilities that those projects present. This includes improving the production through new well techniques; drilling more wells, postponing operations and investments, and even divesture, among many others. The results show that the traditional approach represented by the Discounted Cash Flow (DCF) valuation cannot alone be used to help the decision makers make optimal decisions.

Acheampong (2010) carried out a real option analysis on the marginal oil field development projects using a case of UKCS. The aim was to show the applicability and the value of real option analysis in examining if the value of a sample oilfield in the UKS is different if valued by the traditional DCF (NPV) methodology in comparison to real options approach. The binomial lattice model was used because of the flexibility it provides in incorporating early exercise. Results indicated that the traditional DCF was lagging behind that of the option values for deferral and expansion option. But only a marginal change was exhibited by the abandonment option with respect to the DCF value. Acheampong's findings implied that management will be better off by considering various options in their field development decisions.

Numerous studies like the works of Ayodele and Frimpong (2003), Akinpelu and Omole (2009), Adamu et al. (2013), Ezemonye and Clement (2013), Idigbe and Bello (2013) AdeogunandIlledare (2015), Ashore (2015), Ekeh and Asekomeh (2015) and Akinwale and Akinbanmi (2016) have analysed the investment decision in the Nigeria marginal oil fields through economic evaluation using traditional models via the net present value, internal rate of return, profitability index, payback period and probabilistic approach via Monte Carlo simulation. Real Options Analysis (ROA) which serves as a step beyond Traditional Economic Approach because of its ability to incorporate flexibility and option value has also been used by different researchers like[Lund (1999), Abisoye (2007), Acheampong, (2010)]to evaluate investment analysis in the oil and gas sector in United Kingdom, Norway and many more countries. Results showed that investment shows higher return on investment when analysed with ROA compared to when analysed with traditional approach.

However, the study already done on marginal fields have failed to consider investment in oil and gas project in the analysis of investment decision in the marginal fields' development in Nigeria. The researchers also failed to take into account all the uncertainties that might arise as a result of Niger Delta Militants Insurgencies (NDMI) especially now that the country is losing a whole lot of money to NMDI. Finally, no research has been done on investment analysis of marginal fields' development in Nigeria using Real Options Approach. It is therefore necessary to consider investment in the oil and gas industry especially now that the Federal Government is working towards minimising gas flaring. This project will emulate the methodology used by some researchers by using real option model because of its ability to incorporate flexibility and option value, to analyse investment decision making in the Marginal Fields' Development in Nigeria after incorporating all uncertainties that pose threat to the marginal fields' project especially considering the fact that investment in marginal fields is irreversible and are prone to different uncertainties. This will enable us to know whether investment in the Marginal oil and gas fields is economically viable after experiencing various uncertainties.

METHODOLOGY

Model Building

The model for the traditional valuation includes the Net cash flow (NCF), Net Present Value (NPV), Internal Rate of Return (IRR), Payback Period (PP) and Maximum Cash in Red (MCR).

In the probabilistic approach (incorporating risks and uncertainties), the algorithms that were adopted in the economic analysis was in line with all Monte Carlo simulation processes. This includes building a model, adding stochastic assumptions, running @RISK software. The model described in this section captured the main risks and uncertainties present in oil & gas field development projects in Nigeria.

Deterministic MODEL Formulation

This study adopted and modified the discounted cash flow model via NPV used by Awotiku (2011).

Net Present Value

The following is the formula for calculating NPV:

$$NPV = \sum_{t=1}^{k} \frac{NCF_t}{(1+r)^t} \quad (1)$$

where,

NPV = Net Present Value

Net Cash Flow (NCF_t) = Cash Inflow – Cash Out Flow (2)

Cash inflow = Gross Revenue

Cash outflow for a marginal fields' project = Royalty, Capital Expenditure, Operating Expenditure, profit oil split to the government, Bonus, Tax, Other costs (NDDC, SDC e.t.c.)

$$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - TAX_t - VAT_t - PO/G_t - OTHER_t \quad (3)$$

A modification was done to include a variable (Militant Insurgency) which is considered a pressing issue facing the oil and gas investment in Nigeria

$$NCF_t = GR_t - ROY_t - CAPEX_t - OPEX_t - BONUS_t - TAX_t - VAT_t - PO/G_t - OTHER_t - MIS_t$$

(4)

Where,

MIS_t = fn (Revenue lost as a result of annual shut down, cost of repairing/ replacing vandalised pipeline for onshore and cost of replacing blown- up facilities for offshore and finally ransom paid as a result of kidnap.

$NCF_t = investmentaftertaxinyeart$

$GR_t = grossrevenueinyeart$

$ROY_t = royaltiespaidinyeart$

$CAPEX_t = Totalcapitalexpenditureinyeart$

$OPEX_t = TotalOperatingexpenditureinyeart$

$BONUS_t = TotalBonusPaidinyeart$

$TAX_t = Totaltaxespaidinyeart$

$VAT_t = Valueaddedtaxpaidinyeart$

$PO/G_t = Profitoilsplittothegovernmentinyeart$

$OTHER_t = othercostspaide.g.NDDC, SCD, Abandonmentcost$

MIS_t= Militant Insurgency:

Components include the total cost incurred as a result of Militant insurgency. Three major variables were captured here;

Offshore:

i. Revenue lost due to Annual shut down (days) as a result of blown up facilities. This was captured by multiplying the number of shut down (days) by the oil price in those days.
ii. Ransom paid as a result of kidnapping: This is the total amount of money paid as a result of the kidnappings.
iii. The Cost of repairing or replacing the blown up facilities:- This is the total cost incurred in repairing or replacing all the blown up facilities

Onshore:

i. Pipeline vandalisation: This includes the total cost incurred during the process of repairing or replacing the pipeline vandalised through insurgency
ii. Kidnapping: The total amount of money paid to kidnappers in order to get the release of the workers kidnapped.
iii. Revenue lost as a result of Annual shut down (days):- This is total revenue lost for the period of shutting down production from the fields. This is as a result of vandalised pipeline facilities.

r = hurdle rate or rate of return

t = time in years

k = total number of years in cash flow

Gross Revenue > Total investment cost = Positive NPV (profit oriented investment)

Gross Revenue < Total investment cost = Negative NPV (Investment will result in a loss)

Internal Rate of Return

Calculating IRR will be as follows:

$$\sum_{t=1}^{n} \frac{NCF_t}{(1+IRR)^t} = 0 \qquad (5)$$

In equation 4.16, the net cash flow at time t is known, but IRR must be found from the above equation as an unknown variable.

Based on this criterion, if the project ROR is more than the companies' hurdle rate or interest rate of investment, then the project is considered economical and profitable, and if it is less, then the project will be evaluated non-profitable. (Ladeinde, 2015)

Payback Period

The payback period, also referred to as the breakeven point is defined as the expected number of years required for recovering the original investment. At this point, the cash inflow exactly equals the cash outflow. This yardstick is used along with at least one other measure of profitability since it does not provide a meaningful decision criterion by itself.

When related to the useful economic life of an investment, the payback figure is used as an indication of whether the investment is repaid within the economic life. The discounted payback period accounts for the time value of money and it provide information on how long funds are tied up. Also future expected cash flows are generally believed to be riskier than near-term cash flows.(Main, 2010).

Maximum Cash in Red (MCR)

Maximum Cash in Red is the maximum cumulative cash outlay in the project life cycle. It is also known as maximum cash flow exposure

Model Assumptions

In the evaluation of our deterministic model, many factors were put into consideration. Various factors were considered especially those that has never been captured by existing models. Assumptions made were based on information and data gotten from the Nigeria National Petroleum Corporation, Annual reports from Onshore and offshore already producing fields, Literatures, Federal Inland Revenue, U.S Energy Information Administration. Main factors considered include: capital expenditures, operational expenditures, oil and gas price, Royalty rate, Petroleum profit tax, militant insurgency. Based on this information a base case scenario was designed (See table 2).

Table 2: Model Assumptions

Name	value
Discount rate	12.5%
Escalation Rate	3%
CA	20% (Ist 4 years, 19% 5th year)
ITA	20%of Tangible CAPEX
Oil price	$40/ BBL
Gas price	$3.50/MSCF
Oil OPEX	10% of revenue
Gas OPEX	10% of revenue
Costs recoverable	80% of revenue
Gas royalty rate	7% onshore, 5% offshore
SDC levy	1% of gross revenue
NDDC levy	3% of total cost incurred
Educational tax	2% of assessable profit
PPT	65.75% of taxable income
CITA	30% of taxable income
Estimated ransom paid for both	Offshore: $5million per year Onshore: $5million per year
Annual shut down for oil investment only	Offshore: 40days per year Onshore: 50 days per year
Annual shut down for oil and gas investment	Offshore: 50 days per year Onshore: 70 days in a year
Facilities replacement cost for oil investment only	Offshore: 4% of tangible CAPEX Onshore: 2% of tangible CAPEX
Facilities replacement cost for oil and gas investment	Offshore: 5% of tangible CAPEX Onshore: 3% of tangible CAPEX
Total Capex for oil investment only	Offshore:$479 million dollars Onshore:$336 million dollars
Total Capex for oil and gas investment	Offshore: $801 million Onshore:$ 621million
Timing	
Investment year	2013
First oil	2016
Production Period	15 Years

Binomial Lattice

The binomial lattice model has the advantage of being flexible and it's therefore suitable for real options valuation since it can be adjusted to the specific conditions of a project.

Assumptions in Binomial Option Pricing Model

One simplifying assumption that the Binomial Option Pricing Model makes is that over a certain time period, the underlying asset price can only do one of two things: go up, or go down

In detail, the assumptions in the binomial option pricing model are as follows:

1. There are only two possible prices for the underlying asset on the next day.
2. The two possible prices are the up-price and down-price
3. The underlying asset does not pay any dividends
4. The rate of interest (r) is constant throughout the life of the option
5. Markets are frictionless i.e. there are no taxes and no transaction cost
6. Investors are risk neutral, i.e. investors are indifferent towards risk (Simpli learn, 2013)

Six-Step framework for the resolution of a valuation problem using the binomial technique

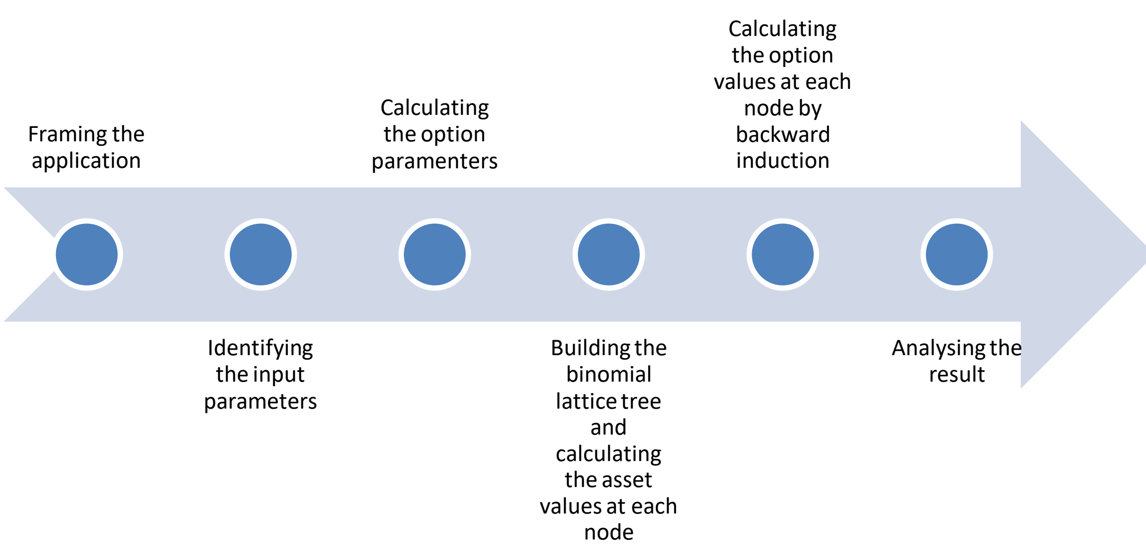


Figure 3: Six-Step framework

Framing the application**:**

Framing a real option is more difficult than framing a financial option. It involves describing the problem in trouble-free words and pictures, identifying the option, and stating clearly the contingent decision and the decision rule. These must be identified very clearly. Keeping the problem simple and making it more understanding will help the communication of the results more efficiently so as to get upper management‘s buy-in.

Identifying the input parameters:

The basic input parameters for the binomial method to value any type of option include the underlying asset value, strike price, option life, volatility factor, risk- free interest rate, and time increments to be used in the binomial tree.

i. **Underlying Asset Value (S_0):** The value of the underlying security at time zero represents the underlying asset value. With real options, however, the asset value is estimated from the cash flows.
ii. **Risk free interest rate**: This is the theoretical rate of return of an investment with no risk of financial loss.

$$r_f = In(1 + r_d) \tag{6}$$

Where, r_f and r_d are the continuously and discretely compounded risk-free rates, respectively

iii. **Exercised price:** The price at which a specific derivative contract can be exercised. A strike price is mostly used to describe stock and index options, in which strike prices are fixed in the contract. For call options, the strike price is where the security can be bought (up to the expiration date), while for put options the strike price is the price at which shares can be sold.
iv. **Volatility factor (σ):** Volatility is an important input variable that can have a significant impact on the option value and is probably the most difficult variable to estimate for real options problems. It represents a measure of the variability of the total value of the underlying asset over its lifetime, as the uncertainty associated with the cash flows that comprise the underlying asset value. The volatility factor σ used in the option models, however, is the volatility of the rates of return, which is measured as the standard deviation of the natural logarithm of cash flows returns, which are the ratios of a certain time period cash flow into the preceding one.

$$\sigma(T_2) = \sigma(T_1) * \sqrt{\frac{T_2}{T_1}} \tag{7}$$

Calculating the Option Parameters:

The option parameters are intermediates to the final option value calculations and are calculated from the input variables. These are the up (u) and down (d) factors and the risk-neutral probability (p) required for the binomial solution.

A Simple approach to the solution of binomial lattices is the risk-neutral probability method, which assumes a risk-free rate for discounted cash flows throughout the lattice. This method applies to every kind of option and the calculations involved are easy once you determine the problem parameters; results are significant for the most common cases and quickly obtainable, making this an efficient method for Real Options Analysis solutions. The up and down factors, u and d, are a function of the volatility of the underlying asset and can be described as follows:

$$u = exp(\sigma\sqrt{\delta t}) \quad (8)$$

$$d = exp\left(-\sigma\sqrt{\delta t}\right) = 1/u \quad (9)$$

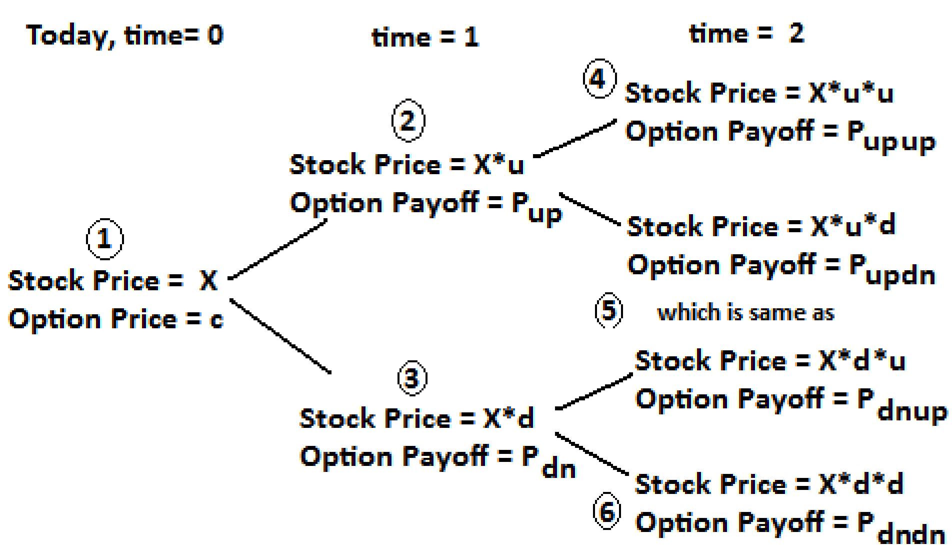
Where σ is the volatility (%) represented by the standard deviation of the natural logarithm of the underlying free cash flow returns, and δt is the time associated with each time step of the binomial tree. The risk-neutral probability, p, is defined as follows:

$$p = \frac{\exp\ (r\delta t) - d}{u - d} \quad (10)$$

Where, r is the risk-free rate.

Building the Binomial Tree and Calculating the Asset Values at Each Node of the Tree:

The binomial tree is built based on the number of time increments selected. The underlying asset value at each node of the tree is calculated starting with Stock Price or Option Value at time zero at the left end of the tree and moving toward the right by using the up and down factors.



Calculating the Option Values at Each Node of the Tree by Backward Induction:

Starting at the far right side of the binomial tree, the decision rule is applied at each node and the optimum decision selected. The option value is identified as the asset value that reflects the optimum decision. Moving toward the left of the tree, the option values at each node are calculated by folding back the option values from the successor nodes by discounting them by a risk-free rate and using the risk-neutral probability factor. This process is continued until you reach the far left end of the tree, which reflects the option value of the project. Whereas asset valuation shows the value of the underlying asset at each node without accounting for management decision, the option valuation step identifies the asset value that reflects management's optimal decision at that node.

Analysing the Results:

After the option value has been calculated, the appropriate first step is to compare the net present value derived from the Discounted Cash Flow method with Real Options Analysis and evaluate the value added as a result of the flexibility created by the option(s). In order to get a better perspective on the option solution, several analyses can be performed on the sensitivity of the option value to input parameter variations, or to different management decisions. To gain more information, option value changes are estimated in particular situations, such as the presence of jumps or leaks, private risk, multiple sources of uncertainty, staged options chains and so on.

Sources of Data

Primary Data

An in-depth interview was conducted on some officials, the deputy director of the Marginal fields bidding process at the Department of Petroleum Resources, (DPR), already producing marginal fields staffs, in order to get information and data which was used to identify the risk and uncertainty involved in the marginal fields' development.

Secondary Data

The Secondary data used in this study were obtained from the Department of Petroleum Resources (DPR), Nigerian National Petroleum Corporation Annual Statistical Bulletin, U.S Energy Information Administration, published articles from journals and consultant reports, Annual and semi-annual reports of some performing marginal field operators.

EVALUATION AND INTERPRETATION OF RESULTS

Deterministic Result

A spreadsheet-based deterministic economic model was employed in the evaluation of the marginal oil and gas field projects to evaluate the investment opportunity through single point analysis. Cash flow, profitability and scenario analysis were carried out.

Cash Flow Analysis

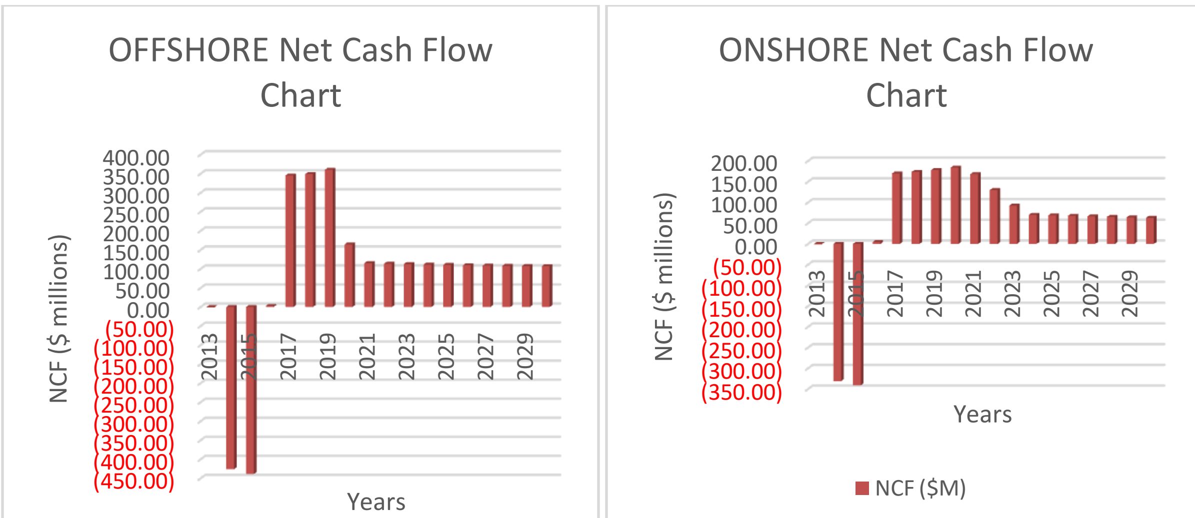


Figure 4: OFFSHORE and ONSHORE NCF CHART

Figure 4 above show the project net cash flow, which is forecasted to be positive for most of the years (2017-2030). There was a negative cash flow before 2017 for both fields because those years are the construction period of the fields and where capital is mostly invested, but after that period, net cash flow will be positive throughout the oil and gas producing periods.

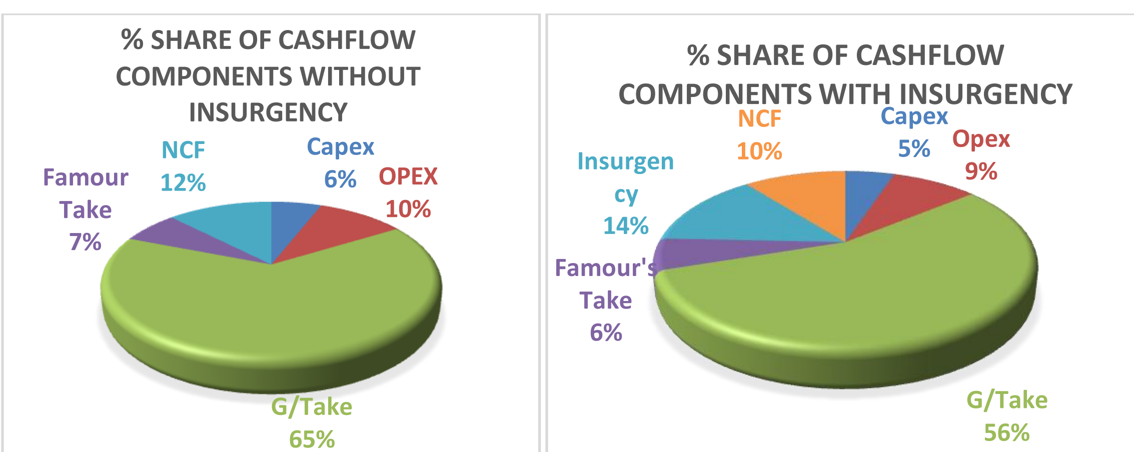


Figure 5: Percent Share of Cash Flow of offshore projects

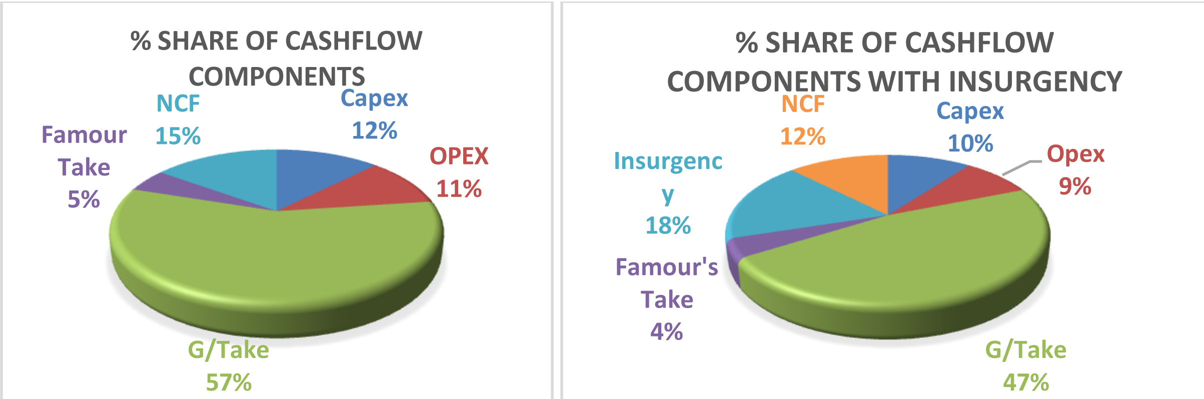


Figure 6: Percent share of Cash flow of onshore projects (oil investment only)

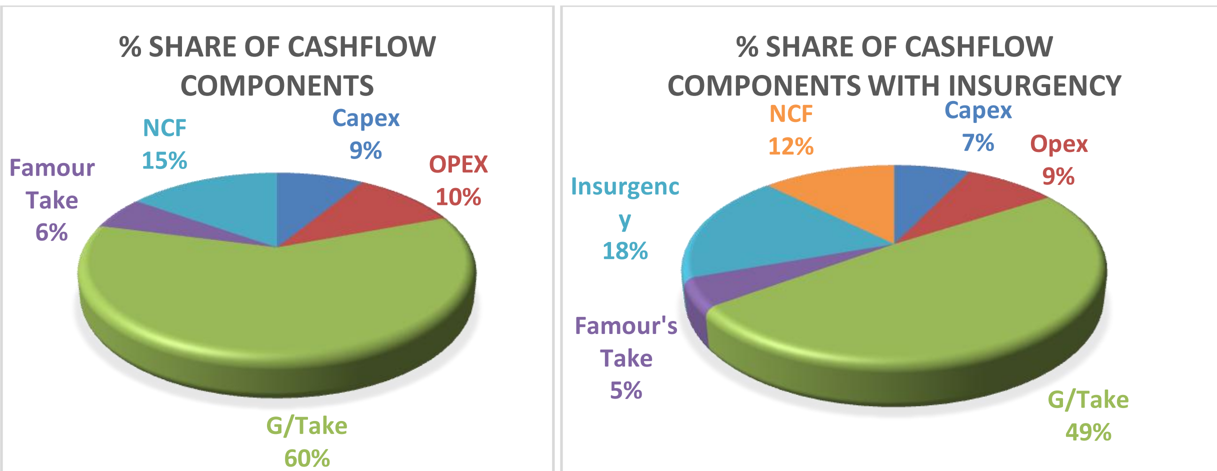


Figure 7: Percent share of Cash flow of offshore project (oil and gas investment)

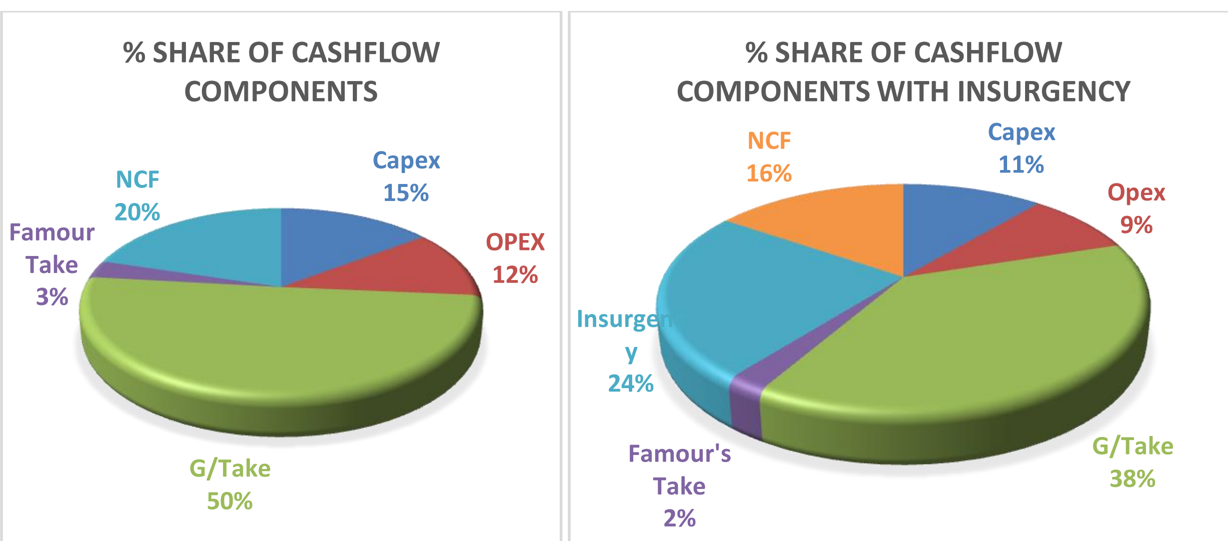


Figure 8: Percent share of Cash flow of onshore project without Insurgencies (oil and gas investment)

Figures 5 & 6 show the Cash flow components of the onshore and offshore investment for oil project only. While Figures 7& 8 show cash flow components of the offshore and onshore investment for oil and gas projects. The results show that the total investor take (Net cash flow i.e. the investor share of profit plus the CAPEX and OPEX, total famour take (royalty) and total government take (Government share of profit + tax and Royalty) without experiencing militant insurgency is higher than when insurgency is experienced in the marginal fields' sector. This indicates that when the sector experiences vandalisation, blown up of facilities, kidnap, it tends to affect the percent share of profit.

Table 3: Offshore Profitability Results

Indicator	Values of oil investment only
NCF	$1,044.09 Million
NPV	$200.16 Million
IRR	21.5%
Payback period	5 Years
MCR	-262.23
PV of Free Cash Flow	$634.67

Table 4: Onshore Profitability Results

Indicator	Values of oil investment Only
NCF	$423.18 Million
NPV	$23.76 Million
IRR	14%
Payback period	6 years
MCR	-188.55
PV of Free Cash Flow	$328.21

The Analysis returned a positive NPV after tax at a discount value of 12.5% for investing in oil project only

Sensitivity Analysis

Due to the uncertainties which have been identified, it is assumed that some of the input factors would likely affect the profitability of the onshore and offshore marginal fields. These uncertainties manifest in Discount rates, oil and gas prices, investment cost, etc. Therefore, to capture these uncertainties, variables used in the deterministic model are considered to behave stochastically which then result in a probabilistic model.

Distribution Assumptions

This signifies the probability distribution assumption made for each variable used in the evaluation of the marginal fields. Triangular distribution was used for some of the variables because it best estimates the distribution using the minimum, maximum and the most likely values. Uniform distribution was used for the remaining variables because it best estimates the distribution using equal probability between the minimum and maximum values.

For the offshore project, CAPEX was assumed to have a triangular distribution because it ranges from $550 million to $950 million with a most likely value of $836.4 million while for the onshore, it ranges from $400 million to $800 million with a most likeliest value of $650 million according to information from already producing marginal fields. Oil OPEX for both offshore and onshore assumed a triangular distribution with a most likely value of 10 and a minimum and maximum value of 48 and 20 percent of the revenue respectively for both fields based on information from already producing marginal fields. Similar assumption was made for gas opex with 5, 10 and 15% of revenue as the minimum, most likeliest and the maximum values respectively for both fields this is also based on information from already producing marginal fields. The Discount rate is also assumed to have the same distribution with most likeliest value of 12.5% and a maximum and minimum value of 15% and 10% respectively for both offshore and onshore fields (information from already producing marginal fields). Petroleum profit tax for both fields is assumed from Federal Inland revenue service to be 50%, 65.75% and 85% for minimum, likeliest and maximum values. Table 4 summarises the distribution assumption of the offshore and onshore projects.

Table 4: Distribution assumptions for offshore and onshore projects

Distribution Assumption for Offshore Project					Distribution Assumptions for Onshore Projects				
Input parameters	**Minimum**	**Likeliest**	**Maximum**	**Distribution type**	**Input parameters**	**Minimum**	**Likeliest**	**Maximum**	**Distribution type**
Capex ($M)	550	836.4	950	Triangular distribution	Capex ($M)	400	650	800	Triangular distribution
Oil Opex (% of revenue)	8	10	20	Triangular distribution	Oil Opex (% of revenue)	8	10	20	Triangular distribution
Gas Opex (% of Revenue)	5	10	15	Triangular distribution	Gas Opex (% of revenue)	5	10	15	Triangular distribution

Discount Rate (%)	10	12.5	15	Triangular distribution	Discount Rate (%)	10	12.5	15	Triangular distribution
PPT Rate (%)	50	65.75	85	Triangular Distribution	PPT Rate (%)	50	65.75	85	Triangular Distribution
Gas Price ($/Mscf)	3.00	3.50	7.00	Uniform distribution	Gas Price ($/Mscf)	3.00	3.50	7.00	Uniform distribution
Oil Price ($/bbl)	30	40	70	Uniform Distribution	Oil Price ($/bbl)	30	40	70	Uniform Distribution
Ransom Paid ($M)	1	5	10	Uniform Distribution	Ransom Paid ($M)	1	5	10	Uniform Distribution
Annual Shutdown (days/year)	20	50	100	Uniform Distribution	Annual Shutdown (days/ year)	30	70	120	Uniform Distribution
Replacement Cost (% of Tang. Capex)	2	5	10	Triangular Distribution	Replacement Cost (% of Tang. Capex)	.5	3	6	Triangular Distribution

Table 4...

Sensitivity Analysis Results

Figures 9-14 show the sensitivity analysis of different variables on the key profitability indicators reviewed in this study (NPV, IRR and Payback Period). The sensitivity analysis showed the effect of changes in the input parameters.

NPV Analysis

Offshore Analysis:

Figure 9 shows that the input variables considered have either positive or negative effect on the NPV. The oil and gas prices have a positive impact on NPV, meaning an increase (decrease) in these variables will cause an increase (decrease) in the NPV. While the remaining variables, Discount rate, Annual shut down(days), PPT rate, Total Capex, Replacement Cost, Estimated Ransom paid, Oil OPEX, Gas OPEX have negative impact on the NPV. The Oil price was considered the most sensitive variable with a positive impact of 71%, this indicates that an increase (decrease) in the oil price will cause a 71% increase (decrease) on the NPV. This means that a slightest fluctuation on the oil price will have a significant effect on the net present value. This is followed by the Discount rate up to oil OPEX, which had a negative impact on the NPV. This simply indicates that an increase in the variables will cause a decrease in NPV and vice versa.

Onshore Analysis:

For the onshore project (Figure 10), the gas and oil price also had a positive impact on the NPV. In the case of the onshore, the gas price was the most sensitive on the NPV with a positive impact of 53% impact. This indicates that an increase (decrease) in the gas price will cause a 53% increase (decrease) in the NPV. This simply means gas price is very significant in the onshore oil and gas project. This is followed by the oil price with 51%, then the discount rate down to the oil OPEX.

In Summary, both the offshore and onshore showed that both gas and oil price have a positive relationship with the NPV. This means that an increase (decrease) in these variables will increase (decrease) the profitability of the investment. Other variables had a negative relationship on the NPV.

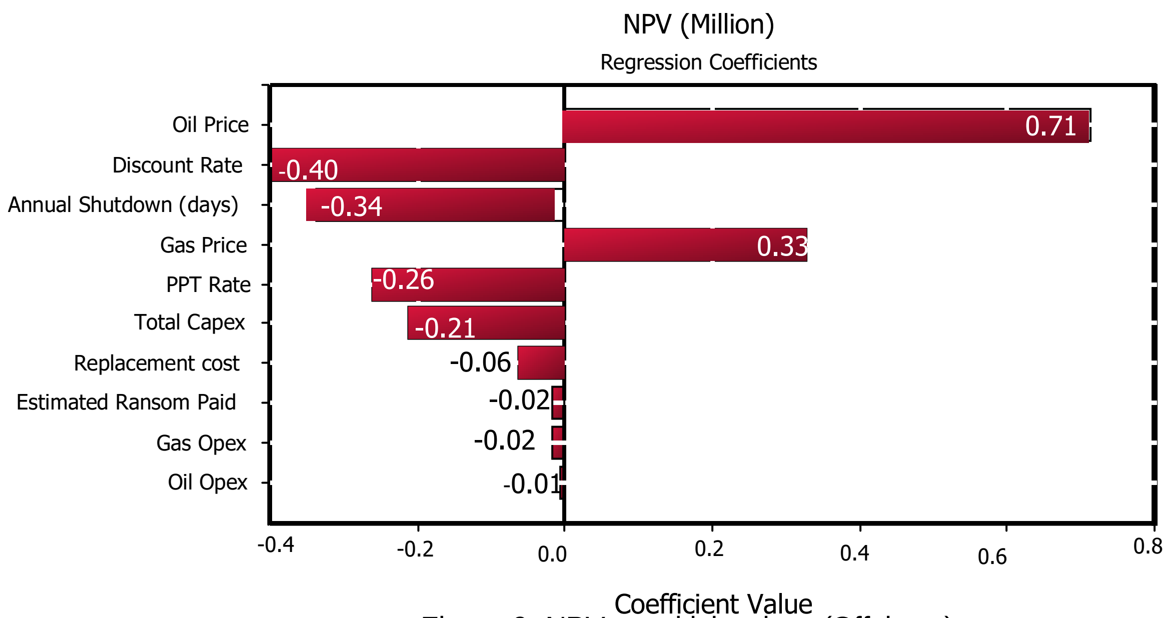


Figure 9. NPV sensitivity chart (Offshore)

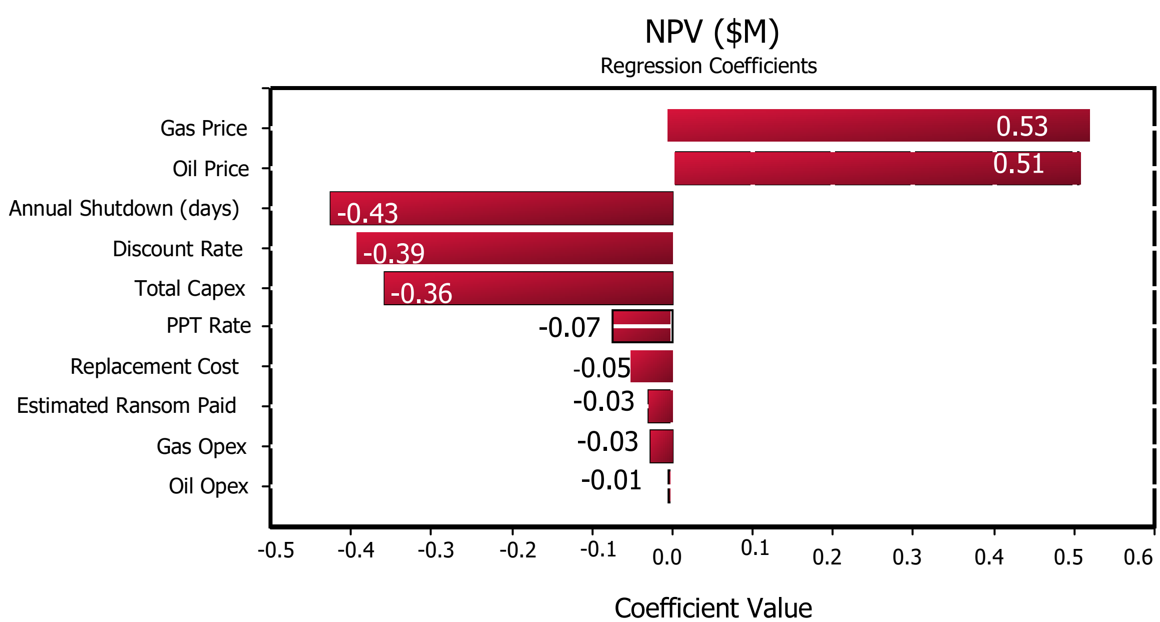


Figure 10. NPV sensitivity chart (Onshore)

Internal Rate of Return Analysis

Offshore:

According to Figure 11, the oil price still remains the most sensitive with 72%, followed by total CAPEX with a negative impact of 47%. Only oil price and gas price has a positive impact on IRR. All others have a negative impact. Meaning an increase in these remaining variables (total CAPEX, annual shut down, PPT rate, etc.) makes the project less profitable while an increase in the oil/ gas price will give a very good rate of return.

Onshore:

In the Onshore (Figure 12), the most sensitive was total CAPEX with a negative relationship of 57%, followed by oil price and gas price, then annual shutdown. Oil OPEX has the least effect on the IRR. Only oil and gas price shows a positive effect on IRR. That is, the higher the oil price and gas price the higher the internal rate of return and vice versa. All other variables have a negative impact on the IRR, meaning, the higher the input variable, the lower the internal rate of return and vice versa.

In summary, the result here still conforms to the NPV sensitivity analysis. Both oil price and gas price have a positive relationship with the IRR. That is an increase (decrease) will increase (decrease) the profitability of our project.

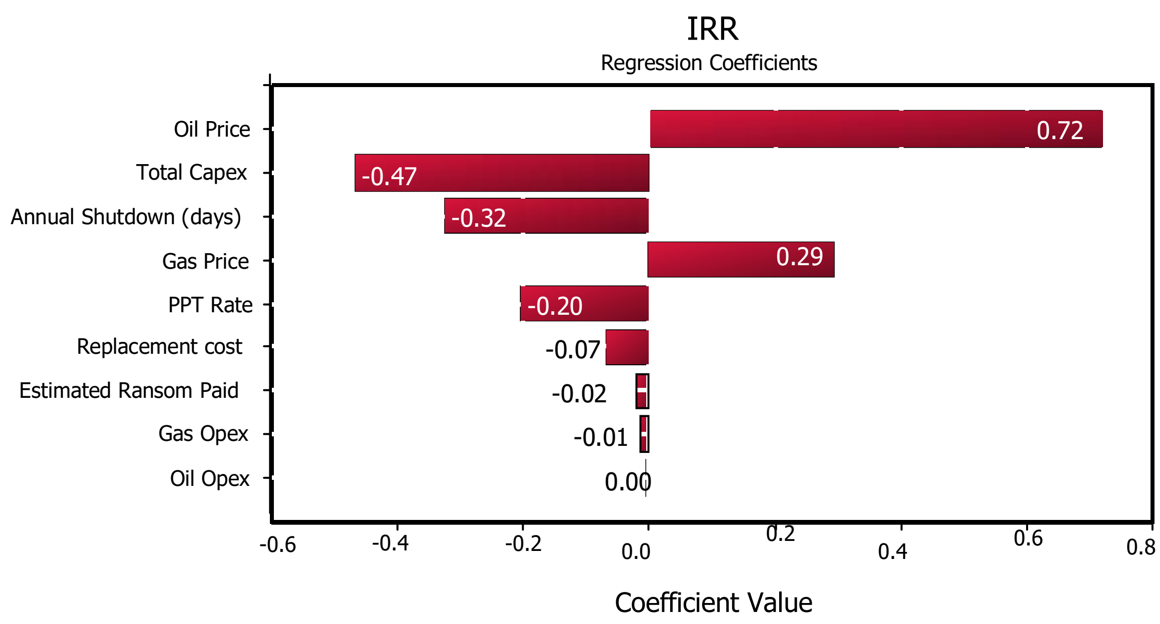


Figure 11: IRR sensitivity graph (offshore)

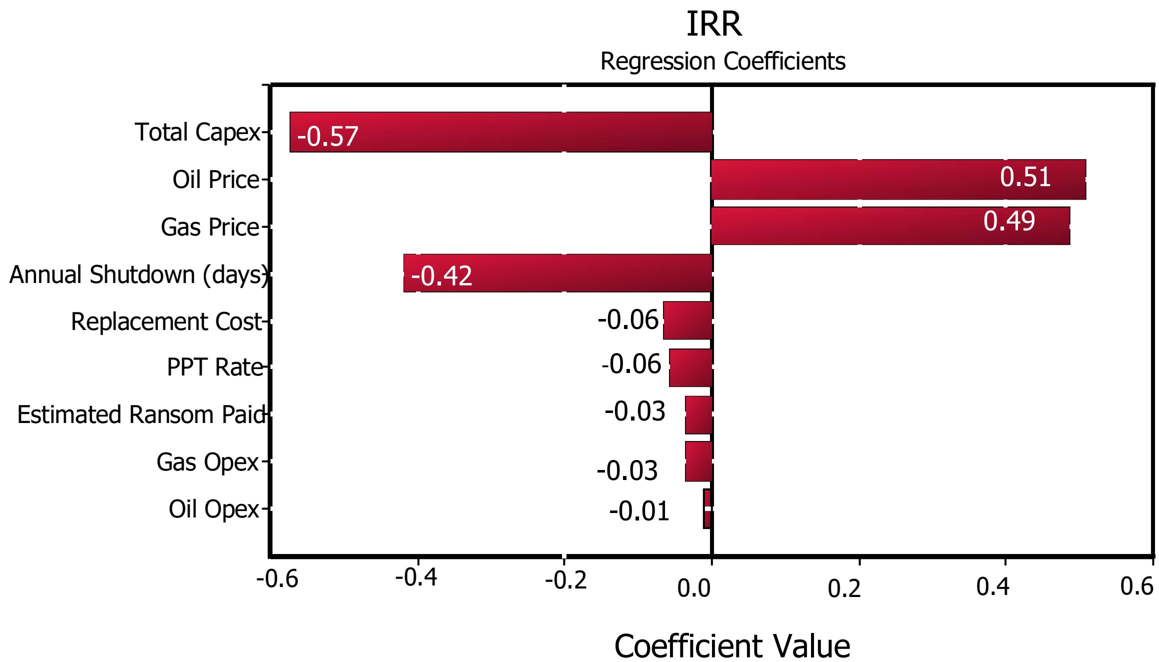


Figure 12: IRR sensitivity graph (Onshore)

Payback Period Analysis

Offshore Analysis:

Figure 13, indicates that the payback period showed a different scenario from the IRR and NPV sensitivity analysis. Both oil and gas price have negative impact on the payback period. This means that the decrease in the price of oil and gas will increase our payback period and vice versa. All other variables have a positive relationship. This means that an increase in the variables will increase the payback period and vice versa. It will as well be noted that the petroleum profit task has no impact on the payback period.

Onshore Analysis:

Also, considering the onshore investment (Figure 14), the payback period also shows a different scenario from the IRR and NPV analysis. The oil and gas price has a negative impact on the payback period. Meaning that, the increase in the price of oil will decrease the payback period and vice versa. All other variables have a positive impact.

In summary, for the offshore project, the oil price was discovered to be the most sensitivity analysis on NPV, IRR and our payback period with little or high change will affect the profitability of the project. While for our onshore project, the Total CAPEX had the most sensitivity on the NPV and IRR. But considering the payback period, the oil price has the most sensitivity impact.

It will also be noted that the same variables portray similar behaviour and impact on the payback period for both fields.

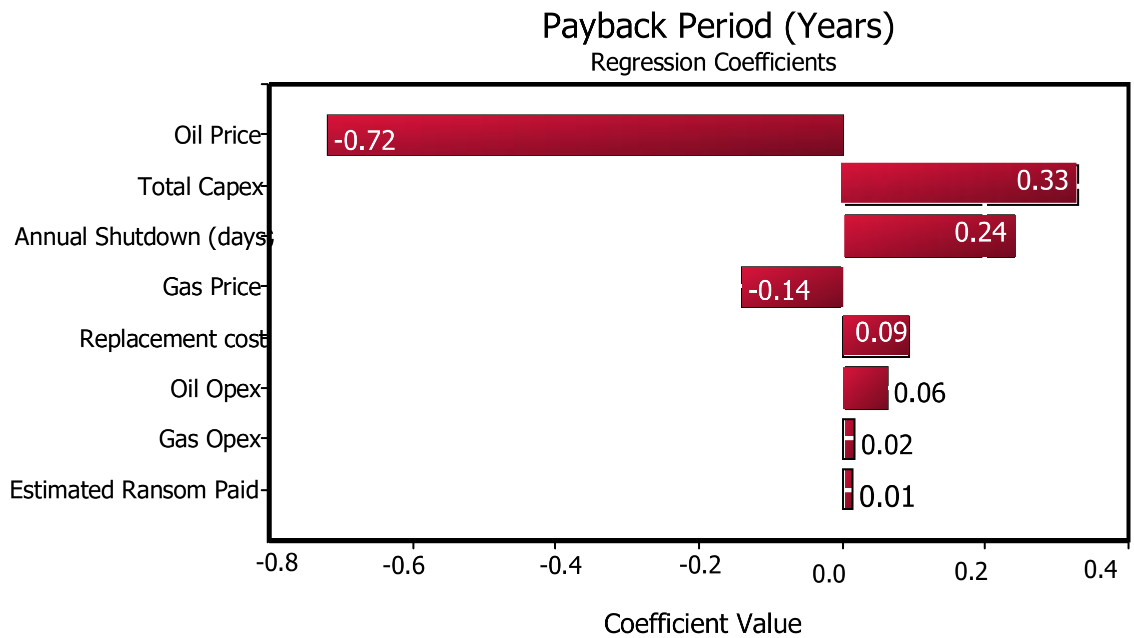


Figure 13: Payback sensitivity chart (Offshore)

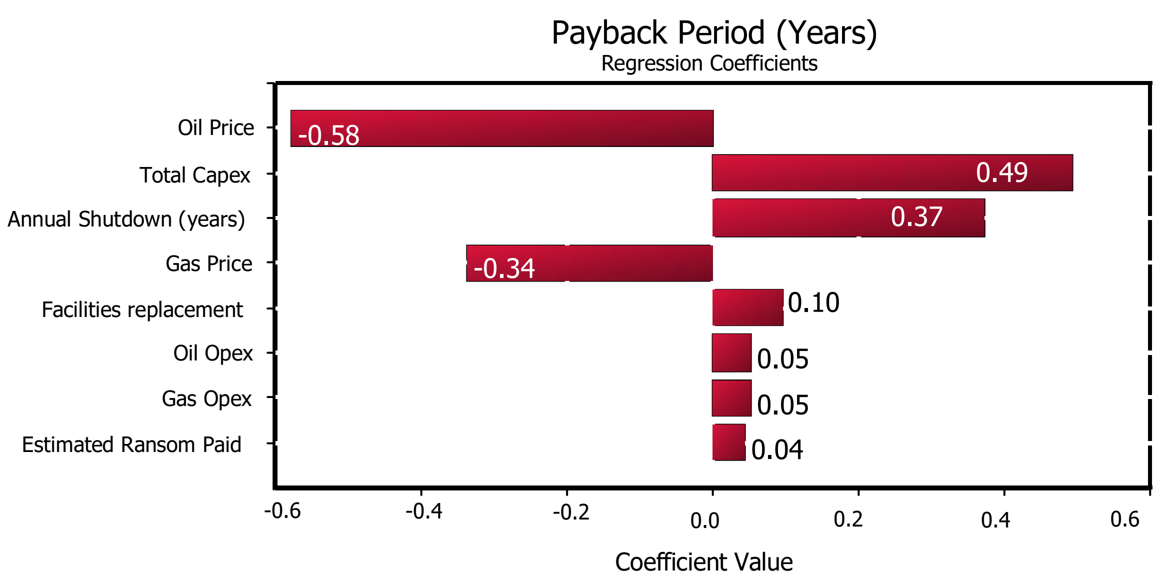


Figure 14: Payback sensitivity chart (onshore)

Real Options Analysis

The real option analysis presented four main scenarios namely Deferral Option (considering oil investment only), Abandonment option with oil investment only, Expansion Option (considering an expansion from oil investment only to gas investment) and finally the Abandonment option with oil & gas investment. All the scenarios were confirmed using the black –Scholes model.

This methodology showed how a project such as this can be evaluated, considering the high volatility of the oil prices, militant insurgencies amongst others. It also presented the flexibilities that can be considered in this project due to these uncertainties. Such flexibilities include:

a. Deferral Option: A right, but not an obligation to invest in oil project now, but delay to a later date when the project faces little or no uncertainty (like decrease in oil price, increase in militant insurgencies e. t. c). The onshore and offshore investment showed an additional value of $173 million and $396 million added value, respectively if the options were delayed without losing out.

b. Abandonment option: A right, but not an obligation to abandon a project when the market is no longer favourable. For the onshore and offshore marginal oil field project, results showed additional benefits of $3million dollars offshore and $2million onshore for the NPV. Pascal triangle confirms a project success rate of 99%.

c. Expansion Option: This is simply the right, but not the obligation to increase investment by utilising all available resources within the field when the market is favourable for a higher Rate of Return (ROR). For this study an expansion of investing in a gas project was considered. This decision presented an increase in the ROR. For the offshore and onshore investment, a total of $606million and $342million was realised after an additional investment of $320million and $372million respectively. Comparing this result with the Traditional Approach (TA) represented by the Discounted Cash Flow (DCF) valuation, justifies that cannot TA alone cannot be used to help the decision makers make optimal decisions.

Tables 5 & 6 and Figures 15 & 16 presents a brief summary of real option results with charts and tables.

Table 5: Expanded NPV (Offshore)

	BLACK SCHOLES	BINOMIAL LATTICE	Real OPTION (Expanded NPV)
Deferral option of oil project	$395 million	$396 million	396+200= $596 million
Abandonment option of oil project	$4 million	$3 million	3+200= $203 million
Expansion Option	$609 million	$606 million	606+200= $806 million

Note: Expanded NPV= Base NPV + Option Value

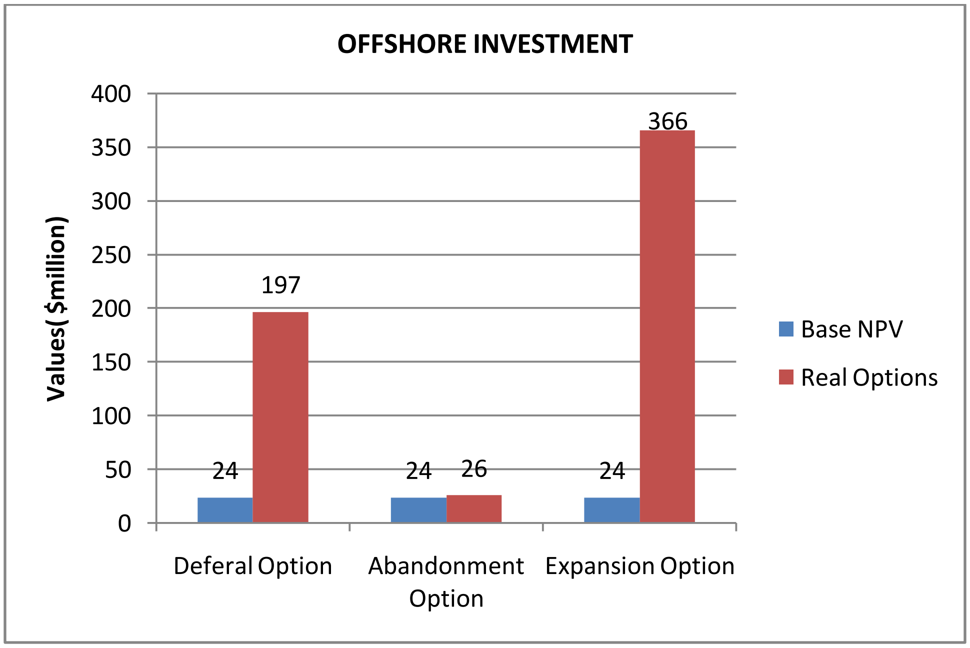


Figure 15: Comparing Base Case NPV with Real Option value

Table 6: Real Option Analysis values (Expanded NPV)

	BLACK & SCHOLES	BINOMIAL LATTICE	REAL OPTION (Expanded NPV)
Deferral Option Without Gas	174	$173 million	173+24= $197 million
Abandonment Option	1	$2 million	2+24=$26 million
Expansion Option	$344 million	$342 million	342+24= $366 million

Note: Expanded option=Base NPV+ Option value

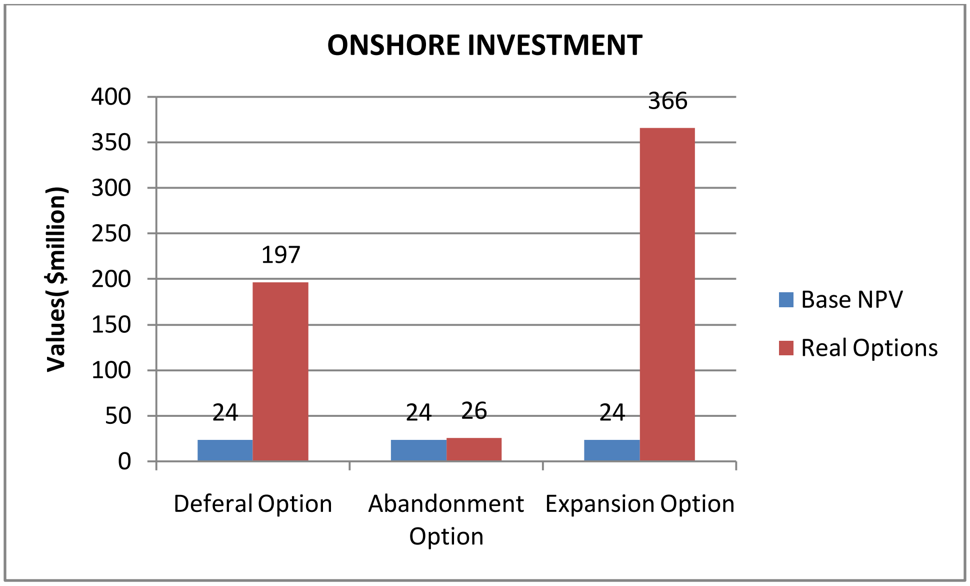


Figure 16: Comparing Base case NPV with Real Option

SUMMARY

	RESEARCH QUESTIONS	RESEARCH OBJECTIVES	METHODOLOGY	RESULT
1	In the midst of various uncertainties like oil price volatility, militant insurgency, amongst others, can Marginal Fields' project be profitable in Nigeria?	To develop a valuation model for NPV by including Militant Insurgencies as key uncertainty variables affecting the marginal oil and gas fields	Discounted cash flow via NPV, IRR and PP	The Analysis returned a positive NPV after tax for both fields'. The decision rule is to accept all projects with positive NPV. This means that the project is economically viable. The result also shows that the Net cash flow, Famour and Government take without Militant Insurgency is higher than when Insurgency is experienced in the oil and gas sector. This indicates that when the sector experiences vandalisation, blown up of facilities, kidnap, it tends to affect the cash flow negatively.
2	What are the key uncertainty variables that can affect the profitability of the marginal fields' project?	Evaluate the effect of risks and uncertainties on the profitability of the marginal fields	Sensitivity Analysis, Tornado and Spider Chart	Sensitivity Analysis; Oil and Gas price has a positive impact on NPV Total Capex, Discount rates, PPT rate, Oil and gas OPEX, annual shut down (days) replacement cost, have a negative effect on the profitability indices

3	How can the applicability of ROA be an active management tool in deciding when to defer, abandon or expand a project in the midst of various uncertainties?	To show the applicability of real options analysis in some selected marginal fields' in Nigeria via Options to delay, abandon or expand at any time during the relinquishment requirement period.	Estimate the embedded project options such as Deferral option, Expansion option and Abandonment option using Binomial Lattice & Crosschecked using the Black and Scholes	Expanded NPV(Base case NPV + option value) <u>Deferral Option</u> The onshore and offshore investment showed an additional value of $173 million and $396 million added value, respectively if the options were delayed without losing out. <u>Abandonment Option without gas</u> For the onshore and offshore marginal oil field project, results showed additional benefits of $3million offshore and $2million onshore for the expanded NPV. Pascal triangle confirms a project success rate of 99%. <u>Expansion Option</u> For the offshore and onshore investment, a total of $606million and $342million was realised after an additional investment of $320million and $372million respectively. <u>Conclusion</u> Results showed that the traditional DCF was lagging behind that of the option values for deferral and expansion option. But only a marginal change was exhibited by the abandonment option with respect to the DCF value

CONCLUSION

The main conclusion is that the onshore and offshore marginal fields' are economically viable and will give better returns on investment under real option consideration. Secondly, decision is more guided using the real options approach than using the traditional approach. This research also ascertained that gas investment is an added advantage if efficiently utilized. That is, it will increase the profit realised from the fields. With the help of the range of the economic and flexibility indices shown in the results obtained, it is a project that investors will be willing to undertake.

RECOMMENDATIONS

The Oil and Gas sector constitutes the bulk of Nigeria revenue (about N1.94 trillion to GDP in 2015) and takes the largest share in export. Any form of shutdown experienced in this sector will have a negative effect on both the economy and the investors. The outcome of this research indicates that;

i. Marginal fields (MFs) are economically sensitive, and investments in them are very challenging.
ii. Annual shutdown of production due to the militant insurgency has the greatest impact among the insurgency variables captured in this research therefore affects marginal oil and gas fields' development.
iii. The study also ascertained that gas investment is an added advantage when considered as an investment by the marginal fields' operators.
iv. Only 12 marginal fields have started production since its initiation in 2003. This is as a result of financial and technical incompetence of the marginal fields' investors

This research thus recommends that;

i. Marginal fields' investors should emulate the use of real options approach model as an economic evaluation technique because decision is more guided than using the traditional financial model.
ii. Marginal fields' investors should involve more in its corporate social responsibilities by involving the participation of the local indigenes simply because Niger Delta citizens are facing a lot of sufferings; no good roads, high unemployment rate, inadequate portable drinking water, no farmland to farm on due to oil spillage. This is the reason why they are always involved in pipeline vandalisation, kidnappings and blowing up of oil and gas facilities. The Federal Government should also involve in more peaceful dialogue with the indigenes of Niger Delta and its environs. This will reduce the act of militant insurgency.
iii. The Federal Government should provide Gas infrastructures and increase gas flaring penalty in order to enable Marginal Fields' investors diversify because majority of the marginal oil fields' still flare close to half of the gas produced due to inadequate provision of infrastructures and regulations by the government. This has made the gas industry frustrated and almost abandoned over the years. This led to Nigeria losing a total of 31.8 billion Naira to gas flaring in the month of February, 2014 (Social Development

Integrated centre) (see http;//thenationonlineng.net/Nigeria-loses-n31-8b-to-gas-flaring/). Many countries around the world have taken into considerations the benefits or advantages of utilising the gas instead of flaring. These include conversion into domestic cooking gas, liquefied natural gas, plastic production and many. So revenue can still be generated from sales of gas which make investment in this sector worthwhile.

iv. The allocation of oil blocks/ marginal fields' by the Federal Government should be transparent and granted to financially and technically qualified investors.

LIMITATIONS AND FURTHER STUDIES

This study was able to capture all cost incurred as a result of Niger Delta militant insurgencies that are posing threat to Marginal Fields' development. As at the time of undergoing this study, only three variables that can be quantified were captured. Further study could be done with the model and knowledge provided by this research by incorporating any Niger Delta militant insurgency variable that might incur cost in the future. This research might basically be used as a starting point for further application of real options analysis for the marginal oil and gas assets. The process of real options analysis illustrated can be useful for any onshore and offshore marginal field companies when evaluating future projects.

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