DESIGN AND ECONOMIC EVALUATION OF FISCAL REGIME FOR ASSOCIATED GAS DEVELOPMENT UNDER PRODUCTION SHARING CONTRACTS IN NIGERIA'S DEEP OFFSHORE

BY

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DEDICATION

This research is dedicated to Knowledge, Experience and the interconnection of words in between.

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ABSTRACT

Petroleum resources production is always based on fiscal regimes, to allocate responsibilities and benefits between parties in contracts. However, clear-cut Nigerian petroleum fiscal regimes only exist for crude oil without equal consideration for natural gas development under Production Sharing Contracts (PSCs). This trend is responsible in part, for continued gas flaring, which leads to economic losses and environmental degradation. Previous studies focused largely on crude oil development, with little attention paid to natural gas development under PSCs. This study, therefore, explored the economic impact of a stand-alone fiscal regime for Deep Offshore Associated Gas (DOAG) under PSCs, with a view to extending the evaluation of the economic viability to non-associated gas projects currently unexplored in the Niger-Delta basin.

Irving Fischer's Capital Budgeting methodology served as the framework, while the Discounted Cash Flow (DCF) model was adopted. A sample of on-stream fields under PSCs in Nigeria was taken with arithmetic average of reserves-in-place and production volumes used as criteria. Data ranged from 2005 and projected till 2027 (the economic life of the asset). Data collected included production volumes, natural gas price, capital and operating expenditures, companies' income tax and Niger-Delta Development Commission (NDDC) levy. Economic indicators such as Net Present Value (NPV), Internal Rate of Returns (IRRs) and payback period of the gas asset were evaluated using the provisions in the Petroleum Industry Act (PIA) 2021 and the proposed fiscal regime for comparison.

The NPVs at 10.0% were $105.21 and $122.13 (in millions) under the PIA and the proposed fiscal regime, respectively. The IRRs were 18.0% under the PIA and 20.0% under the proposed fiscal regime. The payback period was 6.0years for the project under both regimes. The savings indices were 24.8% and 31.2% under the PIA and the proposed fiscal regime, respectively. Natural gas price input (454.07) and production volumes input (421.51) were the most sensitive variables to the project's profitability as compared to NDDC levy (247.17), royalty (242.92) and capital expenditure (241.73). The economic performance indicators, such as NPV, IRR and savings index were higher under the proposed regime than under those of the PIA (2021).

The design and economic evaluation of fiscal regime guaranteed a competitive economic return to investors from natural gas development in Nigeria's deep offshore. The federal government of Nigeria should adopt the stand-alone fiscal regime for exploitation of Deep Offshore Associated Gas under the production sharing contracts for increased investments and economic wellbeing of Nigerians and diminished environmental degradation as a result of reduced gas flaring.

Keywords: Nigeria's petroleum fiscal regime, Nigeria's production sharing contracts, Deep Offshore Associated Gas fields in Nigeria.

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LIST OF ABBREVIATIONS

Abbreviation	Meaning
AG	Associated Gas
NAG	Non-Associated Gas
PSC	Production Sharing Contract
SC	Service Contract
JV	Joint Venture
EIA	Energy Information Administration
IEA	International Energy Agency
OPEC	Organization of Petroleum Exporting Countries
PIA	Petroleum Industry Act
PIB	Petroleum Industry Bill
NNPC	Nigerian National Petroleum Corporation
AGFA	Associated Gas Framework Agreement
NGP	National Gas Policy
NGC	Nigerian Gas Company
IOC	International Oil Company
NDDC	Niger Delta Development Commission
NGFCP	Nigerian Gas Flare Commercialization Programme
SPDC	Shell Petroleum Development Company
NLNG	Nigerian Liquefied Natural Gas
GTL	Gas-To-Liquid
MMSCF	Million Standard Cubic Feet
TCF	Trillion Cubic Feet
BBL	Barrel

NUPRC	Nigerian Upstream Regulatory Commission
DPR	Department of Petroleum Resources
WAGPCO	West African Gas Pipeline Company
IPPS	Independent Power Plants
NIPPS	National Integrated Power Projects
BP	British Petroleum
LPG	Liquefied Petroleum Gas
IRR	Internal Rate of Return
NPV	Net Present Value
PBP	Payback Period
E&P	Exploration and Production
DCF	Discounted Cash Flow
NCF	Net Cash Flow
ERR	Effective Royalty Rate
ROI	Return on Investment
BOE	Barrel of Oil Equivalent
CITA	Company Income Tax Act
NEITI	Nigeria Extractives Industry Transparency Initiative
OPEX	Operating Expenditure
CAPEX	Capital Expenditure
BTU	British Thermal Unit
KWh	Kilowatt/hour

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CHAPTER ONE

INTRODUCTION

1.1 Background to the Study

Global consumption of energy in its available forms is expected to increase. Countries such as Brazil, Russia, India, China and South Africa (the BRICS Nations) are expected to maintain their current economic growth levels of double digits. This is attributed to the fact that the BRICS nations contribute 32.1 percent of the global Gross Domestic Product (International Monetary Fund, 2023). American and European economies also envisage increased economic activities which slowed down during the covid-19 pandemic in 2020. These represent potential increased energy demand and consumption for Industries and resultant pressure on the available sources of energy.

The global energy mix shows an upward trajectory in the use of Natural Gas which is forecasted to increase significantly due to environmental, technological and diversification reasons. According to the Energy Information Administration (2022), it is projected that Natural Gas will assume a greater significance in the global energy demand composition compared to Coal and Crude Oil. Natural Gas currently represents a quarter of global primary energy generation and is considered a great alternative to energy production in the medium term as the world engages in its energy transition journey (International Energy Agency, 2023).

Natural Gas reserves has been on a continuous increase with current proved reserves of 7.4 quadrillion standard cubic feet (OPEC, 2023). The top reserves holders are Russia, Turkmenistan, Iran, Qatar and Saudi Arabia. Nigeria has the highest reserves in Africa and ranks as the seventh largest reserve holder globally. Nigeria has around 208 trillion standard cubic feet of gas, or approximately 33 percent of Africa's aggregate natural gas reserves (OPEC, 2023).

The Nigerian Natural Gas is rich in Natural Gas Liquids and is considered ‘sweet’ due to its relatively low content of hydrogen sulfide and other acids. It is forecasted that with the right resources made available such as funding, distribution network and developed market, Nigeria’s Natural Gas reserves can be increased to about 600 trillion standard cubic feet.

The commercialization of Natural Gas and the decrease in gas flaring activities have seen significant growth over the decades of crude oil production in Nigeria. Nevertheless, the aforementioned advancements have encountered obstacles that impede the anticipated level of achievement by the federal government. The Nigeria Gas Master Plan is the federal government’s most recent effort to seriously develop the Natural Gas infrastructure and Market in a bid to fully commercialize this resource and reduce gas flaring.

Nigeria’s current OPEC production quota stands at 1.4 million barrels per day for crude oil which is a significant reduction from previous levels of 2.2 million barrels per day (OPEC, 2023). This reduction is attributed to increasing incidences of crude oil theft and corruption within the petroleum industry and is frowned at given that increased oil prices in 2007 and 2008 led to increased reserves finds in Deep Offshore Nigeria. Within this period, high oil prices made exploration and development of deep offshore oil projects economic, which otherwise is considered very expensive and technical. This regime of high oil prices and the drive to increase Nigeria’s crude oil reserves from 30 billion barrels to over 40 billion barrels led to the success of several deep offshore projects such as: Shell’s Bonga Field of 250,000 barrels/day at peak production, ExxonMobil’s Erha Field of 200,000 barrels/day at peak production and Chevron’s Agbami Field of 250,000 barrels/day at peak production.

The growth in crude oil reserves and production also increased the production of Associated Gas (AG) but left Non- Associated Gas (NAG) largely un-appraised, due to a lack of robust infrastructure and absence of a developed Market for the resource. Given the existing reserves of natural gas, proven to stand at 208 trillion cubic feet and the right fiscal incentives in place, Natural Gas reserves can be driven up to its potential reserves capacity of over 600 trillion cubic feet (OPEC, 2023).

Nigeria holds more NAG reserves than AG reserves but AG production constitutes over 66 percent of total Natural Gas production in Nigeria (PriceWaterCoopers, 2021). Of the Associated Gas produced annually, less than 10 per cent is utilized in Power Generation, Artificial lift and Gas re-injection projects. The Bonny LNG plant with its kick off in 2000, led to increased levels of Natural Gas utilization though the project was export oriented.

The Nigeria Liquefied Natural Gas Act of 1989 is an example of the instrumentality of fiscal incentives in unlocking the potential earnings and benefits of a resource. This is as the project significantly reduced the flare of previously stranded gas and has placed Nigeria as a major player in the global LNG industry with Nigeria as the 6^{th} largest exporter of LNG Cargoes in the world (British Petroleum Statistical Bulletin, 2022).

A 10 year Tax Holiday given by the federal government of Nigeria in the NLNG Fiscal Act 1989 is the key driver of the success of the Bonny LNG project which placed Nigeria at its topmost position of 3^{rd} world's largest LNG exporter in 2015 and is a classic example of how fiscal incentives can unlock previously un-tapped benefits in government revenues and earnings.

Fiscal regimes

Fiscal regimes are a careful balance between the Host Government and the International Oil Company objectives. They are a system of taxes and incentives designed to achieve the attainment of the important considerations of revenue maximization from a natural resource, employment generation and overall economic development objectives of Government, while guaranteeing improved economic return to the shareholder that the IOC represents. Over the years, the Petroleum Industry Act solely focused on Oil production and gas was viewed as an "accidental" commodity produced with Oil.

To achieve significant commercialization of the vast gas resources, an independent fiscal framework for redistributing natural gas revenues is required, in as much as a standardized natural gas infrastructure network for boosting domestic consumption and exports is needed. Nigeria is known as the "gas province" in OPEC because it has natural gas reserves that are nine hundred times greater than its crude oil reserves (OPEC, 2021). The government has been striving to wean the economy off its reliance on crude oil because of the natural gas industry's immense profit and benefit potential. This has inspired the recent success of attempts to establish the Petroleum Industry Act (2021).

1.2 Problem Statement

Revenues from the Nigerian petroleum industry have fuelled economic and political activities since commercial oil production began in the country. Upstream operations in Nigeria have as a result ignored gas production with a sole focus on crude oil- the hydrocarbon with the most economic rent. Crude oil price volatility and Nigeria’s over dependence on oil revenues have as a result led to calls for the diversification of the economy. The drive towards a gas revolution can therefore, not be achieved if a complete dissociation of these two (crude oil and gas) resources is not achieved.

Although its passage was widely expected, opposition from the oil and gas industry delayed the Petroleum Industry Act. Since the first draft of the law wasn't submitted to the National Assembly until 2009, and the measure wasn't initially passed by the lower house of the National Assembly until 2019, a lot of people in the industry and potential investors had to wait.

Ogolo and Nzerem (2020) analysed the economic effect of the delay in the passage of the Petroleum Industry Bill (PIB) especially the impact on expected return and Government Take on deep offshore investments. They estimated, Nigeria lost over $1.2 billion in deep offshore investments and over $120 million in host government take.

Investment in the petroleum sector also slowed significantly as a result of the PIA's slow passage. The number of new operating rigs in the nation steadily decreased throughout the same period (2009-2019), indicating a decrease in investment interests in the country by the IOCs. As Figure 1.1 illustrates

Figure 1.1 shows that the number of drilling rigs in operation decreased dramatically between 2010 and 2011, and again between 2013 and 2017. This indicates IOCs' decreased enthusiasm for investment due to the slow passage of the PIA, resulting, in fewer new investments and less revenue for the host government.

Nigerian Production Sharing Contracts (PSCs) are structured for oil production alone while natural gas discoveries which are in commercial quantities are reported for negotiation between the producer and the NNPC on contractual basis. The absence of clarity in PSC terms for Associated Gas producers has posed a bottleneck as deductions and allowances in subsisting PSCs are made from oil revenues. Investors have as a result called for a separate fiscal regime for non-associated gas production which will serve as a guide in making investment analysis of prospective natural gas upstream projects in the Country.

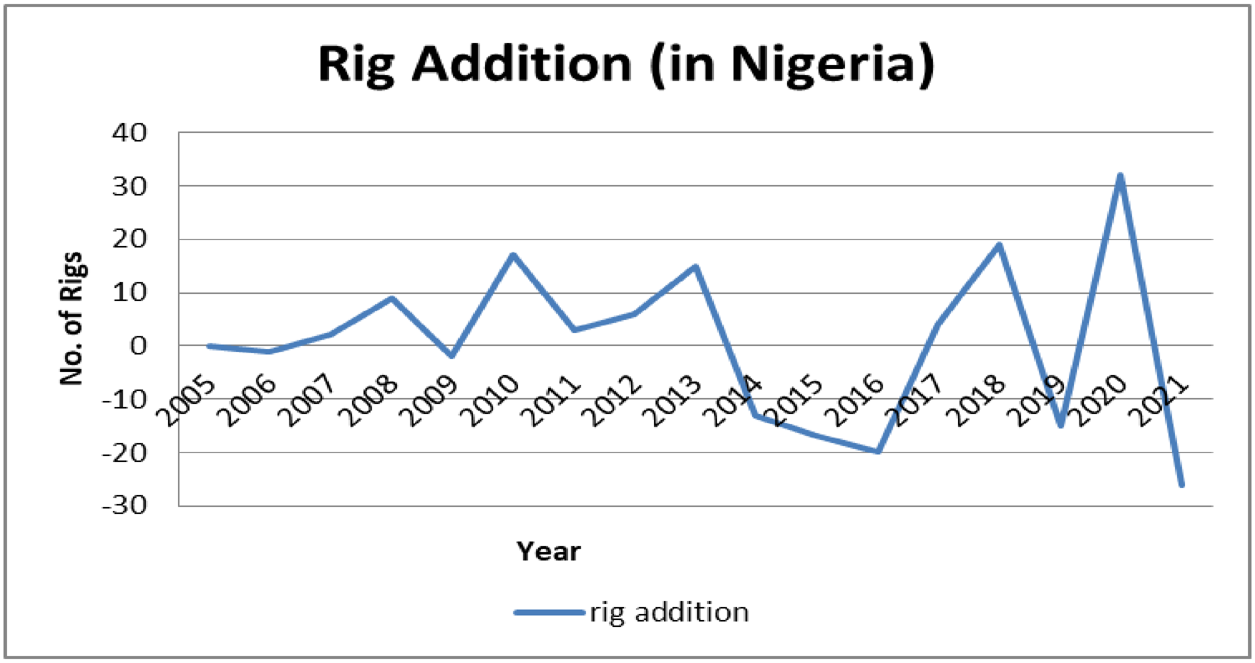


Figure 1.1. Trend in Number of Rigs Added in Nigeria, 2005-2021

Source: OPEC Statistical Bulletin (2021)

Under the recently repealed Petroleum Profits Tax Act (section 11), expenditures of associated gas (AG) and non-associated gas (NAG) are deductible business expenses. Many interpretations have thus resulted from this provision:

(i) It disadvantages investors who do not have oil tax capacity (that is, corporations who don't have oil operations and hence can't deduct gas expenses from oil operations in the same way as upstream Investors in oil projects can;

(ii) It encourages oil corporations to construct gas infrastructure (in certain instances – that are unnecessary to increase their cost base);

In a bid to address the above-listed concerns, the then-proposed Petroleum Industry Bill pledged to take these concerns into account while crafting a new tax structure for the oil and gas industry. However, that neither the old PSC regimes nor the new PIA 2021 have crystallized the fiscal terms for PSC gas projects in Nigeria.

1.3 Research Questions

The study proposes to answer the following research questions:

1. How will a clearly defined fiscal regime for natural gas benefit the host government and potential investors in upstream gas development –deep offshore Nigeria?

2. How will a newly designed fiscal regime for natural gas development –deep offshore Nigeria under the PSCs compare with the fiscal provisions in the PIA (2021) with regards to economic benefits to the host government?

1.4 Objectives of the Study

The specific objectives of this study are to:

1. Design a fiscal regime for natural gas development –deep offshore Nigeria under the PSC regime (completely separate from crude oil).

2. Compare the benefits of the commercial terms for gas production from an associated gas field under the PIA (2021) to the benefits of the commercial terms under a Stand-alone fiscal regime for associated gas.

1.5 Justification of the Study

The Nigerian government before now has to an extent neglected the natural gas subsector, in favour of the large windfalls derived from crude oil production; this neglect has in turn, come at a cost to the environment through gas flaring activities. Gas flaring, as an inevitable option to Natural Gas commercialization has led to huge revenue losses to the federal government.

Mian (2012), Tordo (2006) and Charkib (1995) studied the design and assessment of fiscal regimes throughout the world. Most research on taxation policies or regimes have focused on the economic justification for different tax terms and their effects on investment decisions in the petroleum sector.

In Africa, there is a dearth of literature on petroleum fiscal regime design thus further study on the subject is required. Most studies of Africa and of Nigeria in particular, have examined the fiscal provisions for the petroleum sector across different African countries as a means of measuring the attractiveness of each for crude oil investment. Upstream natural gas has not been identified as a resource in any of these earlier studies, nor has the economic feasibility of developing associated gas fields in deep offshore Nigerian oil and gas concessions via production sharing contracts (PSCs) been evaluated.

This study aims at highlighting the importance of natural gas monetization into perspective as it will address the issues holding up significant investment in the natural gas industry. Increased gas development in Nigeria will not only move Nigeria from a potential gas-nation to a gas-hub but will also attract more economic rent from the nation's abundant petroleum resources.

This study will also be of benefit to investors in the petroleum industry as it will serve as a yard stick in estimating cash flows from potential upstream gas investments in Nigeria's deep offshore which will better inform their decision to invest in such projects. Investors will better appreciate the dynamics and interplay of key determining variables in the gas market and how these affect the economic viability of such projects.

This study will also aid in changing the narrative of natural gas from a by-product of crude oil extraction to a valuable commodity in its own right.

1.6 Plan of the Study

This study is organized into five chapters. Chapter one dwells on the introduction, statement of the problem, research questions and objectives, justification and plan of the study. Chapter two dwells on the literature review and theoretical framework adopted in this study. Chapter three dwells on the research methodology of the study. Chapter four dwells on discussion and analysis of findings or results from the study. Chapter five discusses the summary, conclusion and recommendations of the study.

CHAPTER TWO

LITERATURE REVIEW AND THEORETICAL FRAMEWORK

2.1 Overview of the Nigerian Gas Industry

Nigeria is sometimes referred to be a "gas and oil" country because of its comparatively smaller oil reserves. Nigeria is the biggest natural gas reserve holder in Africa and the 7th largest in the world, with known natural gas reserves of around 208 Tcf and an additional 600 Tcf in untested gas reserves. The proved crude oil reserves in Nigeria are estimated to be 36,890 million barrels, or 207.6 Trillion cubic feet of gas (OPEC, 2023). That means there is more natural gas in Nigeria than there is crude oil, by a factor of more than 980.

Most of Nigeria's gas reserves are discovered in the course of oil exploration. Natural gas infrastructure is currently lacking to develop gas markets. T he country's gas reserves are virtually evenly divided between associated gas (AG) and non-associated gas (NAG), with minimal development of NAG resources. Lacking in implementation of policies and growth drivers in domestic gas usage, Nigeria continues to under-utilize this resource and not fully optimize its intrinsic economic worth to the economy, despite the country's large reserves and the rising need for local consumption.

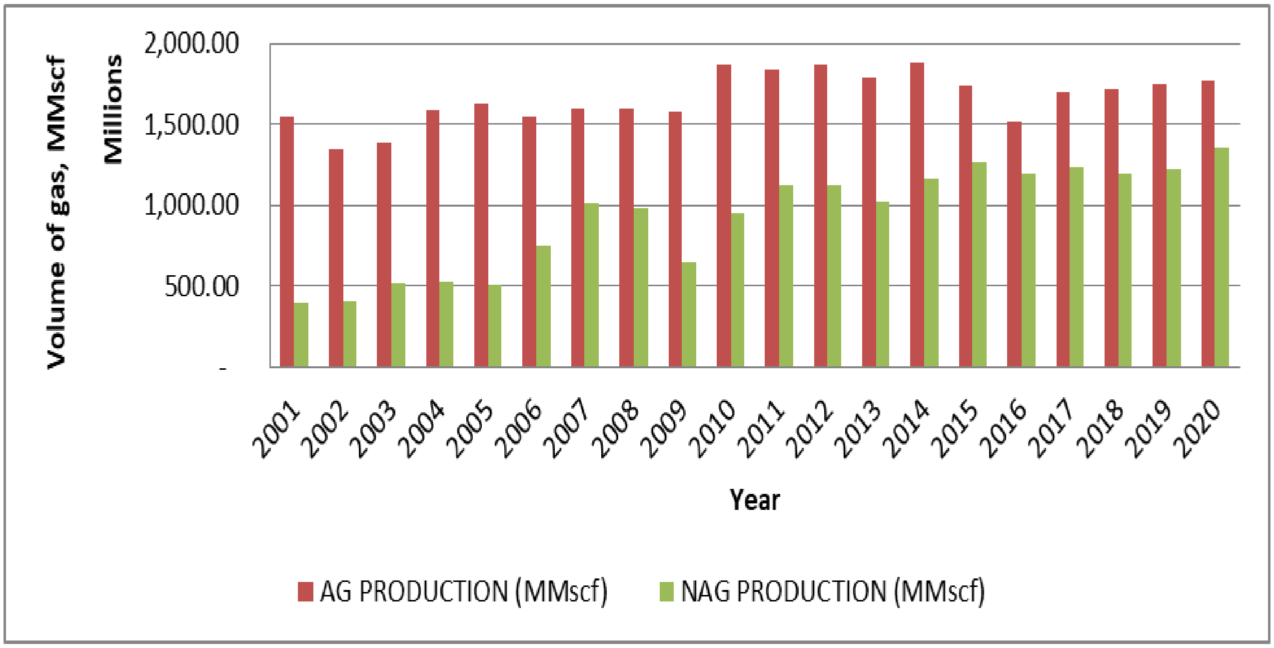


Fig 2.1. Associated VS non-Associated gas production in Nigeria (MMscf)

Source: Nigerian Upstream Petroleum Regulatory Commission (NUPRC), EIA

Figure 2.1 above shows the sources of natural gas produced in Nigeria. Nigerian gas reserves developed are mainly from AG fields while NAG fields are mainly undeveloped or abandoned by many producers because of the infrastructural and fiscal limitations stiffling the industry. It is however noted that NAG fields are increasingly being developed and total natural gas production has been on an increase.

2.1.1 Natural Gas Utilization

When compared to other major gas producers, the country’s natural gas utilization is one of the lowest in the world. This is because there is not enough capital, or infrastructure to adequately utilize recently discovered gas deposits. In 2018, the United States was responsible for roughly 261.3bcf of flared related gas, or around 5.1% of all gas flared globally (World Bank, 2019). Concerned about environmental deterioration and eager to profit from this waste, the federal government and the World Bank have aggressively pushed a Zero flare policy and encouraged significant gas utilization projects.

The nascent natural gas industry in Nigeria began when gas was piped to firms in the southeastern part of the country. From the mid-1960s through the late-1990s, federally funded efforts towards increased gas utilization led projects such as: Delta Steel Aladja, Nigerian Fertilizer Company of Nigeria (NAFCON), Ajaokuta Steel Complex, Egbin Thermal Power Station, and Aluminum Smelting Company of Nigeria (ALSCON) in Ikot Abasi (Akwa Ibom State) all receiving natural gas supplies. The Nigerian Liquefied Natural Gas Company (NLNG), the Escravos Gas-To-Liquid (EGTL) project, the West African Gas Pipeline Company (WAGPCO), the Afam Power plants, and a slew of National Integrated Power Plants (NIPPs) and Integrated Power Plants (IPPs) across the country are just a few examples of relatively new projects that have had significant impacts on Nigeria's ability to utilize its natural gas resource. Gas-lift, fuel for production operations, and re-injection into the reservoir for conservation and pressure control are all applications of AG that have been pushed on the oil and gas sector. Almost 90% (1.5 bscf) of 2019's total output was either re-injected into the reservoir or consumed by end users (NGFC, 2019).

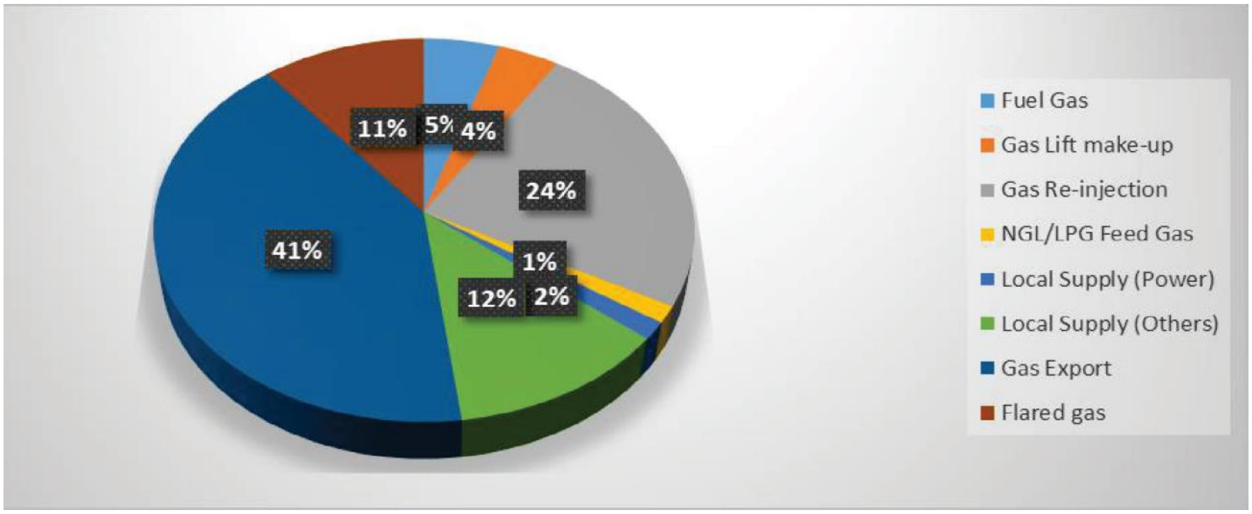


Fig 2.2. Natural Gas Utilization Breakdown in Nigeria, 2021

Source: DPR Annual Oil and Gas Report

Figure 2.2 shows the composition of natural gas utilization in Nigeria in 2021. It can be observed that a total of 1.2 Tscf (41%) of natural gas was exported through the NLNG and other export-oriented gas projects in the country such as the West African Gas Pipeline. About 694 bscf (24%) got re-injected into reservoirs to maintain pressure and stimulate production of crude oil and gas in these assets and were used for the purpose of gas lift in some cases. The Nigerian markets consumed about 44 bscf (1.5%) in power generation and 353 bscf (12%) for servicing gas-based industries. 145 bscf (5%) was utilized as fuel gas while 97 bscf (4%) was used as gas-lift make up for producing fields. About 254 bscf (11%) of natural gas was flared and 51 bscf (1.78%) was used as feed gas (DPR, World Bank 2021).

In terms of reserve holding, many sources characterize Nigeria as a gas-rich but oil-poor country. Awareness, insufficient infrastructure, and unclear tax regimes to promote production and development of this resource are all factors that work against its widespread use. Nigeria is the leading natural gas producer in Africa and the tenth largest in the world, although it is only third in natural gas consumption in Africa and 38th in the globe (BP Statistical Bulletin, 2020).

2.1.2 Gas Flaring

Gas utilization in 1963 reduced gas flaring from 100% to roughly 95%, and remained at this level for the following 15 years (NGFC, 2019). This trend started with the beginning of oil production in the nation. Crude oil prices have had a major impact on the level of activity, which in turn has led to increased output at oil fields and the flare of associated gas. The absence of infrastructure to commercialize the associated gas production generated during crude oil extraction is a major contributor to the large volumes of natural gas flared. In 2020, Nigeria was the seventh most prolific gas flaring country in the world, accounting for nearly 10% of worldwide gas flared (World Bank, 2020) and flaring an average of 16.01 bscf of gas per day (NNPC, 2020).

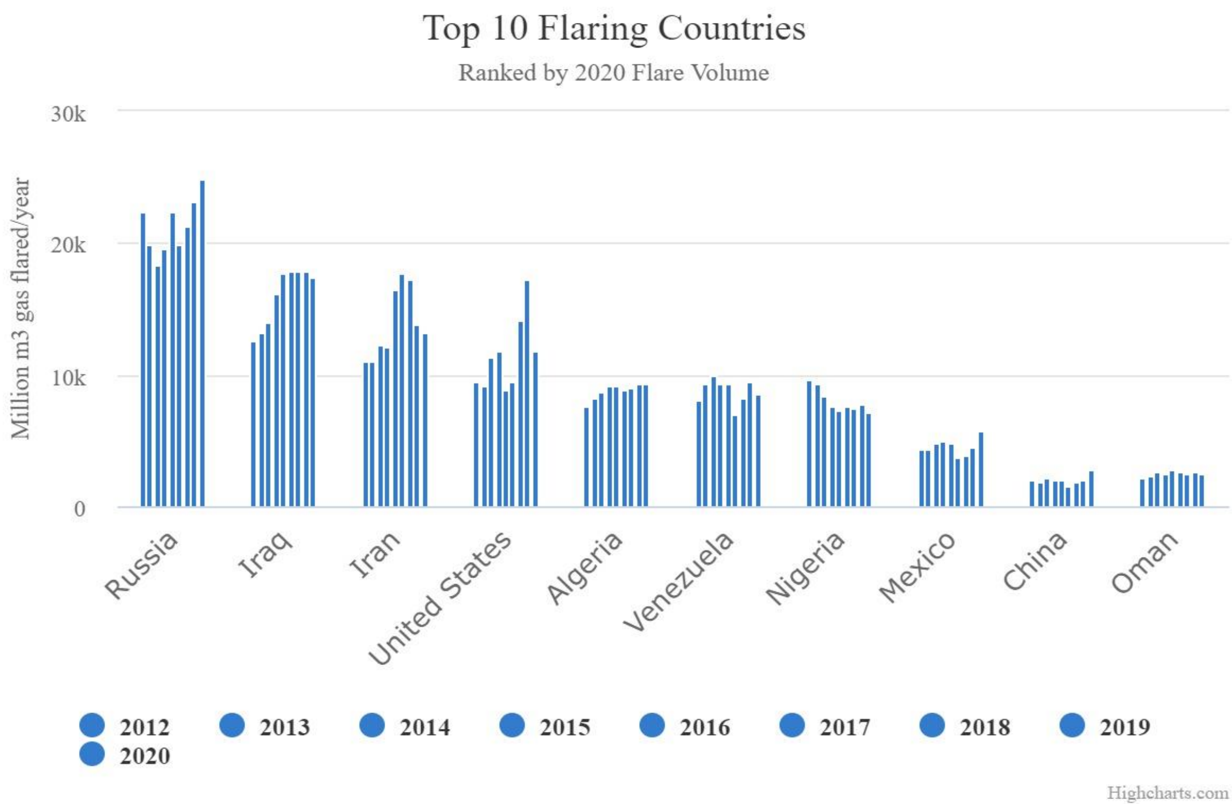


Fig 2.3. Shows the Quantity of Gas Flared by top 10 Most Flaring Nations of the World

Source: NOAA, Colorado School of Mines, GGFR, BP, EIA

In recent times, the federal government has come up with several initiatives, projects, programs and fines to discourage gas flaring in the country. This has so far been regarded successful as 2018 levels of gas flared shows a reduction down to 10.73% in Nigeria (World Bank, 2021). This has moved Nigeria from being the 5th most gas flaring nation in the world to its current 7th position (NNPC, 2020). This achievement is indeed commendable but still leaves room for increased effort as actual quantities flared are still high.

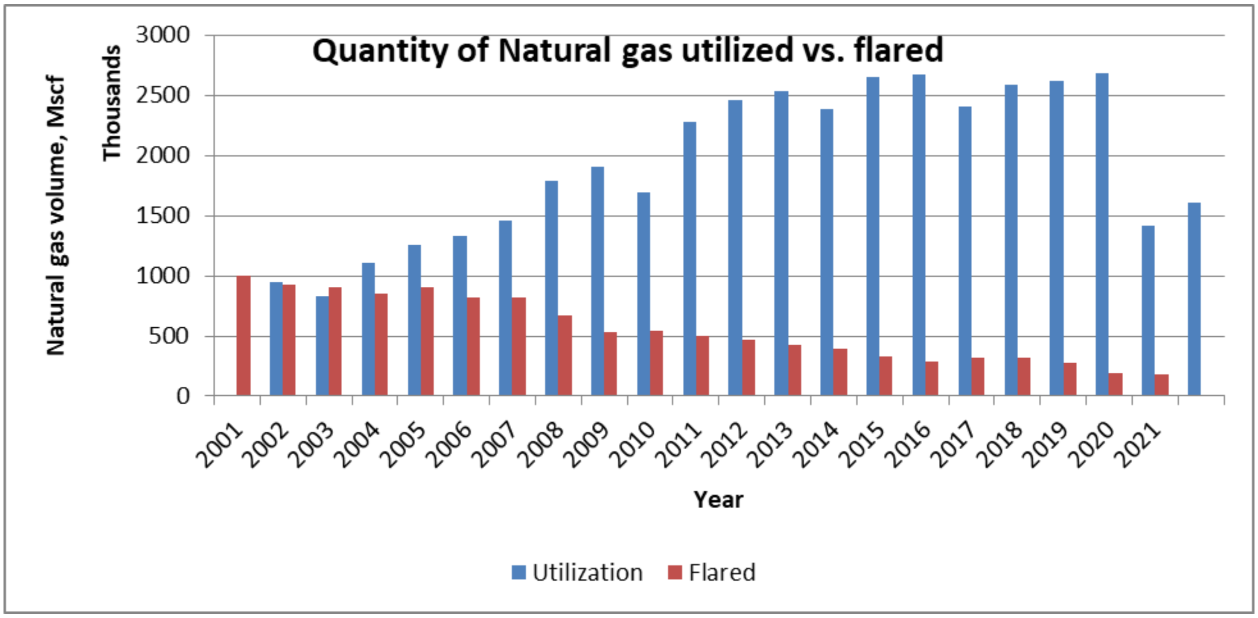


Fig. 2.4. Natural Gas Flared and Utilized in Nigeria

Source: Nigerian Upstream Regulatory Commission (NUPRC)

The government's objectives of successfully establishing a natural gas industry-substantially separate from its oil counterpart with increased domestic gas utilization and putting an end to gas flaring activities have gained momentum over the past decade. This is as a result of reported progress in the areas of Gas-to-Power generation and promotion of LPG usage in Nigerian homes.

The power sector reforms in 2005 brought an increase in the power supply from gas fired plants which increased domestic utilization of this resource. Gas-to-power projects have been encouraged over time because of its inherent advantages over other sources. These include the cheaper economics of production and environmental friendliness natural gas-powered plants have over other sources such as coal. Increased campaigns on utilization of Liquefied Petroleum Gas (LPG) as a preferred cooking fuel also greatly influenced the increase in domestic gas utilization in the country.

2.1.3 Stylized Facts on Natural Gas

The Nigerian government still loses billions of naira every year due to flared gas, despite the fact that the amount of gas flared has decreased dramatically. This loss may be mitigated, however, by bringing additional gas utilization plants on-stream. Losses to the environment and the economy will be mitigated as a result. The charts and graphics in this section illustrate this point:

Natural gas flared as a fraction of total production is seen in Figure 2.5. From 2001 to 2005, the chart illustrates that more than 40% of the total amount of natural gas generated was flared. From 2001 values exceeding 50%, this trend has steadily dropped to its current level of 9% in 2020. This is because more people in Nigeria have become aware of the benefits of using natural gas.

Gas flaring has a significant economic impact on Nigeria. Gas flaring has cost Nigeria billions of naira per year, money that might be used for important strategic development initiatives.

In 2021, Nigeria lost about 281 billion naira, which is enough to fund long-term, community-beneficial development initiatives (see Table 2.1). There are also enormous costs associated with repairing the harm done to the environment as a result of gas flaring operations. The environmental toll of gas flaring in Nigeria is shown in Table 2.2.

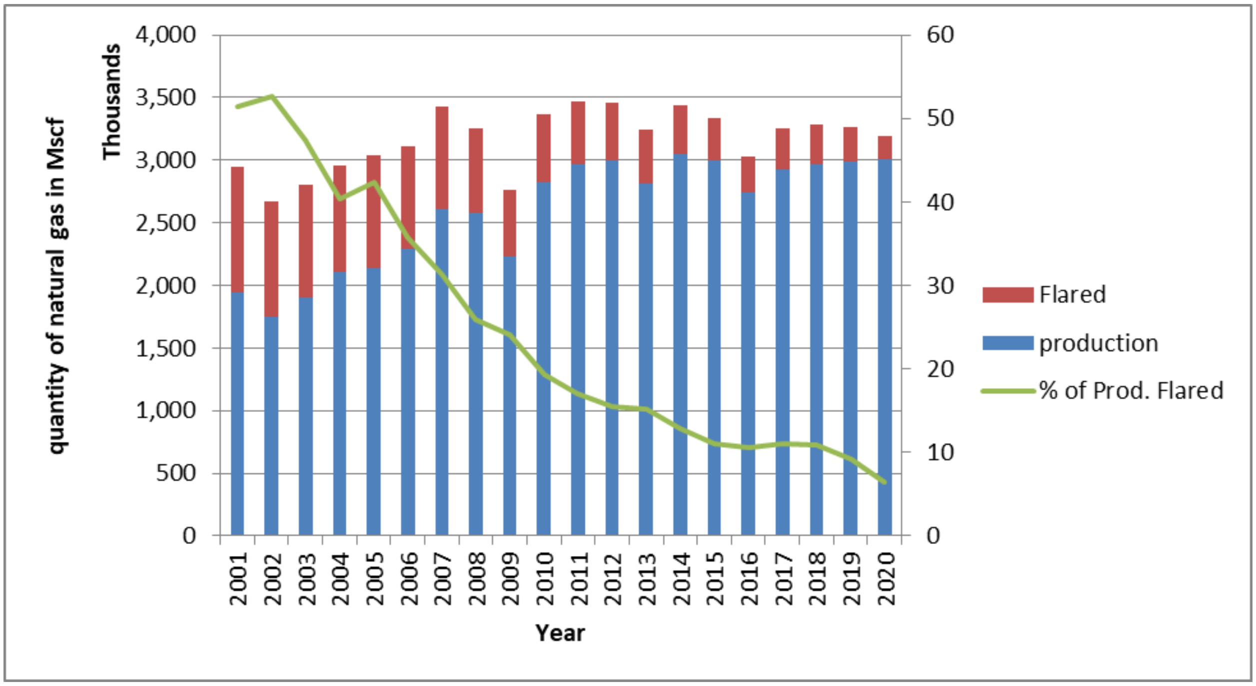


Fig 2.5. Quantity of Natural Gas Produced and Flared in Nigeria, 2001- 2020

Source: NUPRC, World Bank 2020

Table 2.1. Economic Cost of Gas Flaring activities in Nigeria, 2014-2021

Year	Volume of Gas Flared Per Million Scf	Average price of gas per thousand scf/US$	Revenue Lost in US$M	Revenue Lost in (Millions) of NGN	exch. Rate in 2022 Naira (=N=430.5/$)
2021	234,110	2.8	655	281,977.50	
2020	254,262	2.5	635	273,367.50	430.5
2019	276,512	2.7	746	321,153.00	
2018	282,080	2.7	761	327,610.50	
2017	324,192	2.7	875	376,687.50	
2016	288,917	2.6	751	323,305.50	
2015	330,933	2.4	794	341,817.00	
2014	393,839	2.5	984	423,612.00	

Source: NUPRC, World Bank Gas flares Tracker, 2021

Table 2.2. Environmental Costs of Gas flaring activities to Nigeria, 2014-2021

Year	Volume of Gas Flared Per Million Scf	Emissions (Metric tonnes CO2)	No. of Acres of Trees to be planted	cost per acre of tree planted (US$)	Environmental cost of gas flaring (US$M)
2021	234,110	14,586,000	17,870,439	500	8,935
2020	254,262	13,937,332	17,075,706	500	8,537
2019	276,512	15,156,968	18,569,977	500	9,284
2018	282,080	15,462,148	18,943,875	500	9,471
2017	324,192	17,770,529	21,772,052	500	10,886
2016	288,917	15,836,927	19,403,047	500	9,701
2015	330,933	18,140,013	22,224,736	500	11,112
2014	393,839	21,588,236	26,449,421	500	13,224

Source: Erikson (2016); US Environmental Protection Agency; National Environmental, Economic and Developmental Study for Climate Change in Nigeria

As evident in Table 2.2, Nigeria incurs costs in billions of dollars which will be required to sequestrate Carbon dioxide (CO_2) emissions in the atmosphere resulting from its gas flaring activities. In 2021, Nigeria will need over $8.9 billion dollars to effectively sequestrate CO_2 from the atmosphere emitted for that year alone- based on the computations in Table 2.2 above.

In the light of these wastages, the federal government has initiated several plans and policies to stimulate investment and further develop the gas market for more active participation and regulation by industry players both locally and internationally.

Projects embarked upon by the federal government in order to increase domestic natural gas utilization in the country include: the construction of Independent Power Plants and National Integrated Power Projects (IPPs and NIPPs), Gas-to-Liquid (GTL) and Natural Gas Liquids (NGLs) facilities by international oil companies and other stake holders operating in the country. These infrastructures have driven domestic gas utilization levels from 942 million scf in 1999 to about 1,415 million scf in 2020 (NNPC, 2021).

2.1.4 Trend Analysis of Natural Gas in Nigeria

Figure 2.6 shows that natural gas production in Nigeria has consistently risen overtime. Natural gas production levels grew from over 1,940 mmscf in 2001 to 2,300 mmscf in 2010 to about 3,000 mmscf in 2019 (EIA, 2020). In 2013 and 2016 however, there were drops in natural gas production levels which is mainly attributed to the decline in global economic activities in those periods, which in turn had spillover effects on the Nigerian gas industry. Natural gas consumption has also had appreciable increases in levels overtime, from about 220 mmscf in 2001 to about 177 mmscf in 2010 to over 507 mmscf in 2020 (EIA, 2020). Natural gas consumption levels have thus risen over 700 per cent in the last decade. This can be credited to increased sensitization levels on the advantages of LPG consumption over other traditional energy sources such as coal, biomass and kerosene for local consumption.

The economic rent inherent in natural gas export has been an underlying factor in the development of the domestic gas market. Issues such as inadequate local infrastructures and uneconomic pricing have slowed the drive in attracting financial investments in the local market. This however, has resulted in a preference for the liquefaction and/or piping of produced gas to other countries where investors can effectively get returns on their investments over domestic market supply.

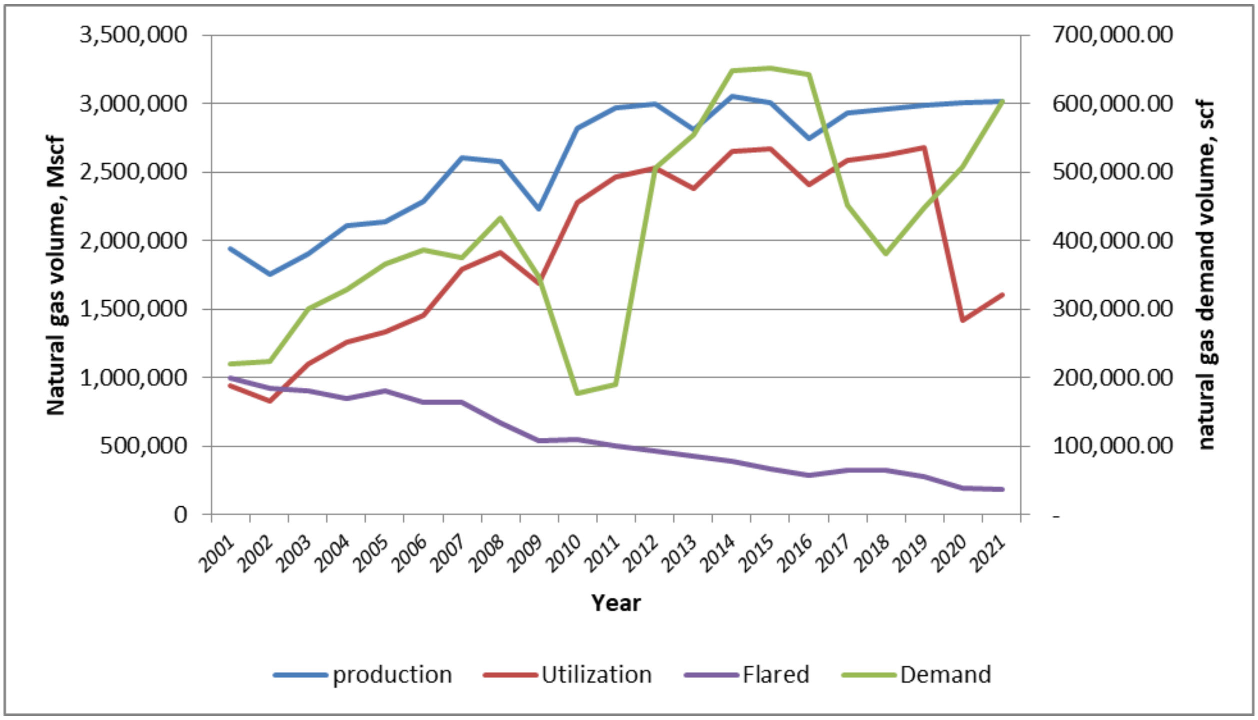


Figure 2.6. Natural gas production, flares, utilization and demand profile

Source: NUPRC, NNPC, OPEC (ASB 2022)

2.1.5 The Petroleum Industry Act 2021

2.1.5.1 Overview of the "Act"

The long-awaited petroleum industry Act was officially consented to by the President of the Federal Republic of Nigeria in 2021. This law before now has been waited upon by industry stakeholders and the country because of the perceived benefits previous drafts of the bill highlighted.

The "Act" (PIA 2021), provides the guide on the governance, regulation and fiscal framework for the petroleum industry and the development of host communities. The PIA 2021 is divided into 319 sections and five chapters. These are discussed briefly below:

Chapter 1: Governance and Institutions.

There are five sections to this chapter. The "Act" (Chapter 1, Part 1) sets out its purposes and vesting provisions in Sections 1 and 2. Section 3 of Part II establishes the Minister's authority, while Sections 4-28 of Part III address the newly established Nigerian Upstream Regulatory Commission. The Midstream and Downstream Petroleum Authority are addressed in Sections 29–52 of Part IV. Sections 53 through 65 make up Part V, which explains the new regulations for the Nigerian National Petroleum Company Limited.

Chapter 2: Petroleum Administration.

Part I of this chapter covers the administration's overarching goals and the management of petroleum resources in sections 66 and 67. Sections 68 through 110 of Part II address administration of upstream petroleum activities and environmental protections, respectively. Sections 111–124 make up Part III, which is dedicated to the management of the Midstream and Downstream Petroleum Operations as a whole.

Sections 125-173 make up Part IV, which is dedicated to the management of gas distribution and processing facilities. Part V deals with the management of downstream and intermediate petroleum liquid activities.

Part VII, which includes Sections 216–233, covers the common requirements for Upstream, Midstream, and Downstream Petroleum activities, whereas Part VI (Sections

209–215) establishes provisions for various connected topics within the Midstream and Downstream activities contained in the preceding parts.

Chapter 3: The Host Community.

Sections 234 through 257 make up this chapter. It starts with a discussion of why this provision was included in the "Act," how the goals of the Act's authors were arrived at, and what steps are needed to ensure that the host communities reap the advantages of petroleum resource development. The requirements of this chapter include the establishment of a trust fund, its financing sources, and others.

Chapter 4: Petroleum Industry Fiscal Framework.

There are eleven sections in this chapter. Sections 258 and 259 of Part I lay out the goals and administration of the budgetary framework, whereas Sections 260 and 266 of Part II deal specifically with Hydrocarbon Tax. Ascertainment of Chargeable Tax is covered in Sections 267 and 268, while Sections 269 through 272 are for purposes of Ascertainment of Chargeable Profits and Consolidation of Tax.

Sections 273–276 of Part V deal with liable parties, whereas the whole of Part VI is dedicated to "Applicability, Accounts, and Particulars."

Sections 288 and 289 of Title VII deal specifically with Tax Appeals. Sections 290-296 of Part VIII are devoted to elaborating on the topic of "Collections, Recovery, and Payment of Tax."

Offenses and penalties in the petroleum business are covered in Part IX, Sections 297-301. Section 302 of Part X allows for the use of Companies Income in Petroleum activities. Sections 303–306 of Part XI cover broad topics relevant to the petroleum industry's tax structure.

Chapter 5 makes miscellaneous provisions concerning legal proceedings, pre-action notice, consequential amendments, repeals, saving provisions, transfers, interpretation, citation and the schedule.

2.1.5.2 ACTS Repealed by the Petroleum Industry Act 2021 .

The newly passed petroleum industry law replaced the following pre-existing laws:

- Associated Gas Re -injection Act, 1979 CAP A25 Laws of the Federation (LFN) 2004, and its amendments;
- Hydrocarbon Oil Refineries Act No. 17 of 1965, CAP H% LFN 2004;
- Motor Spirits (Returns) Act, CAP M20) LFN 2004;
- Nigerian National Petroleum Corporation (Projects) Act No. 94 of 1993, CAP N124 LFN 2004;
- Nigerian National Petroleum Corporation Act (NNPC) 1977 No. 33 CAP N123 LFN as amended, when NNPC ceases to exist pursuant to section 54 (3) of the PIA;
- Petroleum Products Pricing Regulatory Agency (Establishment) Act 2003;
- Petroleum Equalization Fund (Management Board, etc.) Act, 1975;
- Petroleum Profit Tax Act CAP P13 LFN 2004, (PPTA); and
- Deep Offshore and Inland Basin Production Sharing Contract Act (DOIBPSCA), 1993 CAP D3, LFN 2004 and its 2019 amendment. (Ademola, 2021).

2.1.5.3: Fiscal Provisions of the PIA

This section highlights the fiscal provisions for petroleum resources as contained in the Petroleum Industry Act.

From Table 2.3, it is evident that the newly passed PIA still does not address the issue of clarity in fiscal provisions for natural gas development as promised in previous roundtable discussions of the Petroleum Industry Bill. This is highlighted as a problem in section 1.2 of this study and the PIA (2021) fails to address it.

Table 2.3. Fiscal Provisions for Oil and Gas in the PIA 2021

FISCAL TERM	CRUDE OIL	NATURAL GAS	REMARK
ROYALTY	**Production:** Onshore: 15% Shallow water: 12.5% Deep offshore (>200m): 7.5% Frontier Basins: 7.5% **Price:** Below $50/barrel: 0% At $100/barrel: 5% Above $150/barrel: 10%	Not rate specific - but states that natural gas liquids (NGLs) shall be treated as natural gas for the purpose of royalty deductions.	For Crude oil: at prices between $50 and $100/barrel and between $100 and $150/barrel, Royalty is to be determined by linear interpolation.
TAXES: Hydrocarbon Tax (HT) Companies Income Tax (CIT)	Converted/Renewed Onshore licenses and Shallow Offshore: 30% Onshore/shallow Offshore (including Marginal fields: 15% Deep Offshore: Nil Applicable to Crude oil, Condensates and natural gas liquids produced from associated gas operations. 30% which is applicable to all producing companies and operations.	Hydrocarbon Tax (HT) shall not apply to natural gas but shall apply to NGLs produced from AG fields and shall be charged alongside condensates and crude oil from crude oil revenues. CIT: Applicable to all producing companies	The Hydrocarbon Tax is Ring fenced for PSCs to applicable acreages by each producing company. Companies involved with more than one stream must register and use a separate

			company for each stream.
Production Allowance	New Acreages: the lower of 20% of the fiscal crude oil price and $8 per barrel volume. Converted Acreages: the lower of 20% of the fiscal crude oil price and $2.50 per barrel volume.	not rate specific	The PA replaces the Investment Tax Allowance and Investment Tax Credit existing in previous regimes.
COSTS	Capex and Opex for crude oil and condensates shall be deducted from crude oil.	Capex and Opex from AG wells shall be deducted from crude oil but costs from wells solely producing AG shall be deducted from CITA.	

Source: Author's compilation

2.2 Theoretical Review

- **Petroleum Fiscal Systems**

Petroleum fiscal systems are structures of financial, legal and regulatory agreements developed by the host country as a guide to investments in their petroleum industry or jurisdiction. The rules guiding hydrocarbon mining and development in any country is entrenched in their constitution while dynamic rules and obligations which require periodic reviews or that are subject to changes over the life of an investment project are stipulated in policies and other flexible types of legal agreements.

A country's petroleum fiscal system is the framework within which the proceeds from the sale of petroleum are administered and allocated. When conducting business with the government, foreign investors or international oil companies (IOCs) must do so within the parameters established by the laws and system governing petroleum activities of the country in question.

There is the need to increase foreign direct investment (FDI) as nations compete to develop their natural resources and industries (Adedayo, 2016). While national governments compete with one another to entice investors. Therefore, it is crucial to evaluate their performance on a global or regional scale. Though operators and other stakeholders may share similar goals, they may have different approaches to achieving these goals. This means, any host government that wants to maximize revenue must develop the most efficient tax framework for natural resources. This is in order to boost the profitability of oil and gas extraction to attract investors.

The host government therefore has the task of choosing the most qualified firm in terms of resources, credibility, and experience to search, win and develop hydrocarbons in the country. The host government also has the task of judicious utilization of proceeds earned from such investments towards national goals of economic and social development by improving infrastructure, employing more people, and introducing new technologies.

To achieve these, neutral and progressive fiscal systems in terms of economic efficiency need to be designed to collect a disproportionate share of the project's income during prosperous times which can be saved for rainy days. Investors and IOCs, on the other hand, are more concerned with things like the hurdle-rate and the present worth of the project after discounting future cash flows, as well as whether or not the risk taken is commensurate with the projected benefits from the project and the goals and objectives targets of the organization. To achieve this, they strive to choose a nation or area with a tax structure that permits earnings to be repatriated back to investors in their home Countries. In addition, investors like a jurisdiction or nation where operations are conducted in accordance with globally accepted industry standards and the rule of law (Adedayo, 2016).

- **Classification of Petroleum Fiscal Systems**

Concessionary or royalty/tax structures are one sort of petroleum income structure, while contractual arrangements are another. According to (Dharmadji and Parlindunan, 2002), (Johnston, 2003), (Lou and Yan, 2010), and (Mazeel, 2010), these are the most common categories utilized.

All oil producing countries in the world use one or a mix of these fiscal systems in regulating operations in their petroleum industry. Some countries prefer to use a blend of all agreements in different projects depending on the economics which is why investors need to have ample understanding of these systems for optimization of investment strategies and decisions.

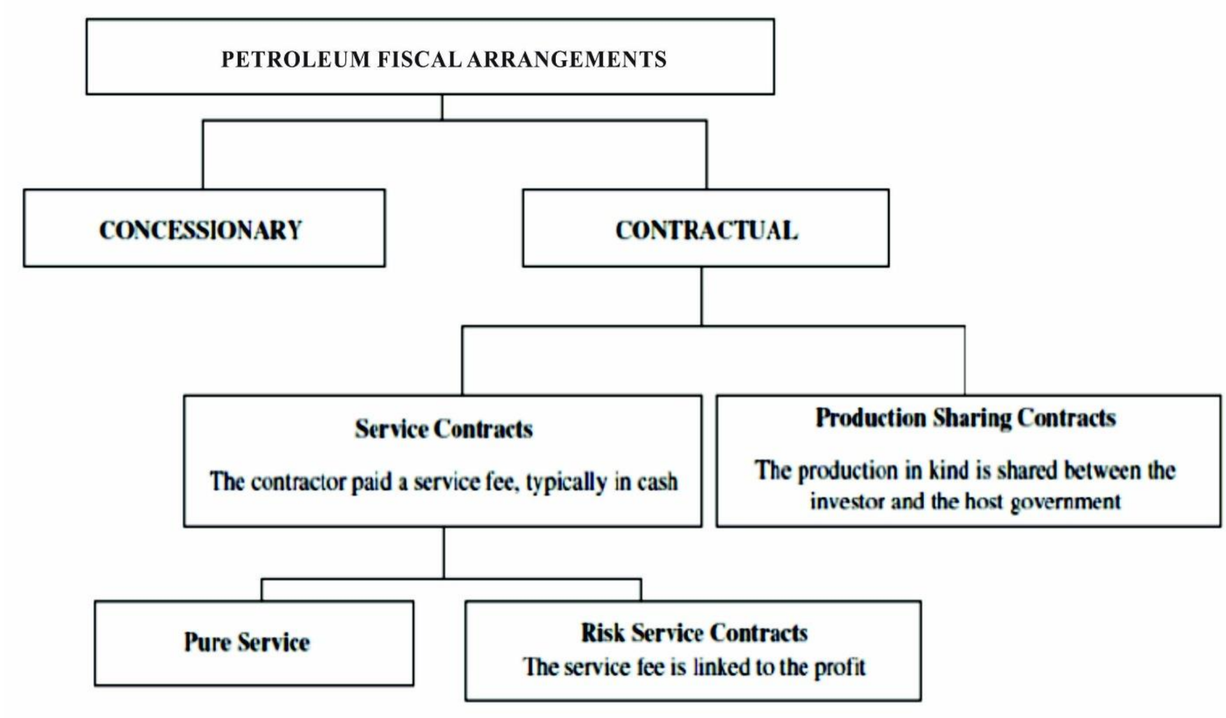


Figure 2.7: Classification of Petroleum Fiscal systems.

2.2.1 Concessionary or Royalty/Tax Systems

According to Anderson (1998) and Kaiser and Pulsiphur (2004), concessionary systems are the most common utilized in petroleum production by host governments and IOCs, with its origins in silver mining in ancient Greece since about 480 BC. These programs were similar to farm-in agreements in which the host government only received royalty on the harvest. However, concessionary agreements developed over time and ushered in a plethora of dynamic fiscal instruments and taxation schedules.

To explore, produce, and sell hydrocarbons from the allotted region, an IOC must have exclusive mining rights from the host government, as defined by Luo and Yan (2010) under a concessionary system. In exchange for the lease, the IOC is responsible for all expenses and must pay the agreed-upon royalty and taxes.

Successful IOCs negotiate and compete for the privilege of developing a certain oil block. The IOC will bear all costs associated with exploring, developing, and extracting hydrocarbons from the licensed oil block. Then, according to the laws and regulations governing hydrocarbon exploration and production in that country, these multinational petroleum companies (MPCs) must pay a ratio of the produced oil or minerals, as well as any taxes on taxable income to the host government. The three pillars of a concessionary system are royalties, deductions, and taxes (Adedayo, 2016). Royalties may be thought of as a type of rent that the government receives from IOCs in exchange for a share of the venture's total income. Royalties are deductible regardless of whether they are paid in cash or in kind. The term "net revenue" refers to the amount of money earned after taxes and royalties have been taken off. After deductions, the remaining amount is the net income. The term "taxable income" is used to describe what's left after expenses like operating costs, asset depreciation, intangible drilling costs, and depletion and amortization have been subtracted from net revenue. Taxes are the last element in a concessional system. Taxable income refers to the earnings from hydrocarbon production that is subject to taxation. It is calculated as Net Revenue less Royalty Income minus All Other Deductions. Depending on the country's petroleum and taxation laws, additional tax rates may be imposed on top of the basic corporate tax rate (Adedayo, 2016).

Some examples of R/T nations include the United States of America, Canada, the United Kingdom, Norway, Peru, and others.

2.2.2 Contractual Systems

The contractual arrangement grants full ownership of petroleum resources to the host governments. Contractual systems, according to (Allen and Seba, 1993) and (Johnston, 1994), date back to the Napoleonic period and are predicated on the idea that the state should hold title to natural resources for the benefit of its inhabitants. The resources belong to the host country, but the Contractor or IOC that produces them and takes on all the associated expenses and risks is entitled to a part of the output as remuneration under the terms of the contract. Conventionally, the government or one of her agencies, usually the National Oil Company (NOC), represents the host nation in contractual agreements, when both parties have participation interests.

The NOC will contract with a FOC or IOC for financial and technical assistance in order to fully explore, develop, and utilize the country's oil and gas reserves. In return for taking on risk and providing services, NOCs often negotiate a share of the profits with the IOC. The agreement between the NOC and the IOC forms the basis of the contractual structure. While the laws of each country govern the essential terms of a contract, many others are open to negotiation. Therefore, host governments and potential contractors frequently use model contract terms as a starting point for negotiations. When new information about factors like the political and economic climate in a region becomes available, it may be possible to renegotiate the terms of existing contracts (Adedayo, 2016).

Production Sharing Contracts (PSCs) and Service Contracts (SCs) are only two examples of the many contractual fiscal systems shown in Figure 3.1. PSCs were originally employed by the Indonesian government in 1967 to spur exploration for and production from the country's oil reserves. The Indonesian PSC Model is still widely used, and it involves contractors (IOCs) paying all expenses associated with petroleum resource development and production in return for a set share of the oil produced. After paying royalties to the host country, after exploring and securing the resource, the Contractor is entitled to a full recovery of all of its costs as (Cost Oil). After the contractor and host government have both recouped their initial oil investments, any remaining profit oil will be split according to the percentages specified in the contract. A part of the contractor's oil income is sent to the host government in the form of a companies' income tax and other progressive tax regulations set in the legislation overseeing petroleum production in the nation. Depending on the circumstances, either the NOC or the contractor may be responsible for footing the cost for the contractor's income taxes. Since the host country's government owns the land which a deposit is found, the contractor can claim only a cost recovery and profit oil share. There are numerous nations that employ PSCs as their primary agreement structure, such as Ecuador, Algeria, Russia, Angola, Equatorial Guinea, Iraq, Egypt, Indonesia and many more. The PSC is one of two primary kinds of service contracts, the other being the risk service contract (RSC), and its essential components are royalties, cost recovery, profit oil, and taxes. For a charge per barrel of oil produced, the IOC under RSC agreements covers all E&P expenses. The Philippines, Iran, and Iraq are among the countries that have signed such accords. Others include Argentina, Brazil, Chile, Ecuador, Peru, and Venezuela. Under Pure Service Contracts (SCs), on the other hand, the host government assumes all financial risks and monetary obligations, while the IOC or contractor is responsible for E&P. Because the host country is paying for everything, only the contractor's technical expertise is needed in these types of agreements.

The results of the study from several countries practicing these fiscal systems show that the advantages of the Production Sharing Contract (PSC) much outweigh those of the Concessionary System. Contractors would also prefer to embark on far offshore projects with less government engagement or control because of the enormous worldwide financial ramifications (Iledare, 2001). The findings of this study provide support for implementing a PSC system.

2.3 Methodological Review

Accounting, capital budgeting, discounted cash flow, and other approaches of investment/project analysis have all been used in various studies examining the PSC petroleum fiscal framework in various nations. However, the capital budgeting approach is the worldwide standard in the oil and gas sector. Many studies have used the capital budgeting approach to analyse the economic performance of oil and gas fields, including Kaiser and Pulsipher (2006), Mentari and Daryanto (2018), Merza and Daryanto (2018), and many others. According to Siew (2001), almost all current economic assessments of oil and gas fields use this conventional method of project analysis, and around 99.99 percent of oil and gas corporations follow suit.

To further investigate how fiscal terms affect oil and gas fields' economic performance; various researches have turned to meta-modelling. Several studies have used the meta-modelling approach to analyse how a country's fiscal terms affect the economic performance of oil fields; these include Adenikinju and Oderinde (2010), Hong and Kaiser (2014), and others. This approach integrates the cash flow model with regression analysis and many methods of estimate. This section reviews the approaches used by previous research on the effect of a country's fiscal parameters on the sustainability of the oil and gas industry.

2.3.1 Capital Budgeting

Inc.com (2019) defines capital budgeting as “essentially a cost-benefit analysis that extends the evaluation of costs and benefits into a longer timeframe and therefore greater emphasis is placed on considerations of the time value of money.” In the same vein, capital budgeting analysis is defined as a process of evaluating the profitability of an investment in capital assets; assets that generate cash inflow in a period spanning more than a year. This involves cash flow projections and the application of economic indicators that show if the investment in a particular asset is profitable or not. In the same way, Mian (2012) explains that: "Capital" is money spent on things like buildings, machines, and other tangible possessions.

A budget is a plan that specifies expected resources after accounting for expected demands. Capital budgeting, therefore, is the process of evaluating potential projects and selecting which, if any, should be allocated funding in the form of a capital budget. Budgeting for capital expenditures involves the strategic use of money that is available now to provide a return in the future.

Capital budgeting is an alternative option to the planning processes involving long-term differential capital investments (Merzi and Daryanto, 2018). Capital budgeting is usually carried out in multinational companies to formulate future scenarios under uncertainty; and it is used to evaluate the success or failure of future projects (Mentari and Daryanto, 2018). Capital budgeting enables management to effectively evaluate the economic value of investment proposals and helps to rank, accept, reject, compare, or select the projects with the utmost economic benefits to the prosperity of the organisation (Mian, 2012). In conducting capital budgeting analysis, an investor is trying to answer the question: given the risk involved, will the cash flow from this asset be sufficient in justifying the investments? Once the answer is in the affirmative, i. e., if the outcome of the analysis satisfies the conditions of accepting a project according to the decision rule of the economic criteria, the organisation can go ahead to invest in the capital project.

Evaluating a project consists of three distinct phases that are all included within the capital budgeting analysis. First, there is gathering information via decision analysis; second, determining a starting point for a position through option pricing; and third, deciding whether to invest based on discounted cash flow (DCF).

Stage 1: Decision Analysis

Decision analysis is carried out using the Multiple Attribute Decision Analysis (also referred to as “decision tree”) which simplifies complex decisions thereby dividing each decision into components parts. This is the first step in capital budgeting. This stage allows a decision maker to gather all the information and gain more knowledge about the project thereby arranging this information to form a decision tree. This enables the decision maker to consider the financial and non-financial criteria of the project; easily identify the important parts of the decision; and, also considers the inputs of others in the decision (Evans, n.d.). In addition, the decision tree helps to highlight the level of uncertainty associated with the project.

Stage 2: Option Pricing

Option pricing, also known as contingent claims analysis, is the second stage in the capital budgeting analysis. This is the art of building a set of options within the capital project in order to account for unexpected changes in the project. This is important in capital budgeting analysis before the discounted cash flow analysis is conducted. Evans (n.d.) highlights three common sources of options, which are: (1) timing options; (2) abandonment options; and, (3) growth options.

Stage 3: Discounted Cash Flows (DCF)

The decision maker may calculate the present value of the capital project's cash flows by discounting the cash flows into the future. This is done by discounting the cash flows expected to accrue to the project in the future to arrive at a value for the project right now. The discounted cash flow (DCF) approach is the gold standard for economic appraisal of oil and gas projects (Mian, 2002; Nakhle, 2008) and is extensively used for investment analysis of capital projects across the globe. To calculate its present value, one must "discount" a future sum, as explained by Evans (n.d.). According to Mian (2012), the profitability criterion may be easily calculated when the cash flow estimations have been established. By factoring inflation, uncertainty, and opportunity cost, this method accounts for the temporal worth of money. This allows a company to gauge whether or not the project is worth investing in over the long haul. Cash-flow models "combine forecasts of all these variables and derive profitability benchmarks from them" (Mian, 2002).

Finding out how much money will be left over after taxes is the main focus of any capital budgeting study. The after-tax cash flow of the project must be determined in order to justify the capital expenditure. There are a number of expenses that must be included into the DCF calculation, including depreciation, working capital, overhead, and financing charges. The cash flow analysis basics were laid out by Mian (2002) with reference to the oil and gas business. Some examples are the treatment of interest on loans and loan payments, the taxation of various costs, the definition of variables, depletion, capital costs, intangible and tangible drilling costs, and the concepts of nominal and real cash flow.

Under the PSC petroleum fiscal system, different countries have different mandatory statutory/fiscal deductions. Royalties, cost recoveries, earnings from oil sales, and taxes are all examples cited by Kaiser and Pulsipher (2006). The Nigerian portion of the contractor's payment is based on sales volume. All of the contractor's costs will be covered by the final profit from the job. The contractor will get its share of the oil revenues and will be liable for income taxes on those earnings. Tax withholding policies vary by nation of residence. Using these variables, we will analyse how changes in government spending affect the value of oil and gas holdings in a country's economy.

Capital projects may be judged economically on the basis of three main factors. They are: Payback period (PBP), internal rate of return (IRR), and net present value (NPV). These financial metrics are used to assess the potential for success of oil and gas ventures.

NPV, or the "Net Present Value"

An investment project's NPV equals its total cash inflows in the present moment minus its total cash outflows. You may sometimes hear the NPV referred to as the "present value" of a business. Arshad (2012) explains that "net present value" (NPV) is "the net present value of the sum of all future cash flows to determine the present value." NPV may be used to determine the profitability of a capital project (Serova, 2015). By discounting the cash inflow and cash outflow of a project by a given rate, the net present value of the cash flow may be determined; this value, in turn, shows the total value gained or lost to the investor if money is invested in the capital project. The Net Present Value (NPV) is often regarded as the most useful economic metric to use in a capital budgeting analysis (Arshad, 2012; Mentari, 2018).

The present value is calculated using the investor's weighted average cost of capital (also known as the discount rate or minimum acceptable rate of return; Mian, 2002). According to Brealey et al. (2011), there are four steps involved in calculating the NPV: (1)

estimating the project's future cash flows; (2) determining the cost of capital (opportunity cost); (3) discounting the project's future cash flows using the cost of capital to arrive at a present value; and (4) estimating the NPV by subtracting the initial investment from the present value.

According to the decision rule, a proposal is lucrative and should be accepted if the project's net present value (NPV) is positive (i.e., larger than zero); otherwise, the idea is not economically feasible and should be scrapped.

ROI (Return on Investment) or IRR

The internal rate of return (IRR) is defined as the discount rate at which the NPV is equal to zero. It is a metric used to assess the potential return on investment for a business venture. To compute the internal rate of return, one must determine the discount rate at which the net present value of the investment is equal to the present value of the cash flows, or NPV = 0. The two most-cited references on this topic are by Evans and Mian (2002). In a more thorough explanation, Mian (2002) defines IRR as "the interest rate received for an investment consisting of payments (negative values) and income (positive values) that occur at regular periods."

Calculating the IRR requires determining the discount rate that yields a negative net present value (Brealey et al., 2011).

Net present value justifies the project's approval if the rate of return is higher than the discount rate. According to Brealey et al. (2011), the "internal rate of return rule" states that an investment project should be approved if its rate of return is higher than the opportunity cost of capital. If the internal rate of return is negative, however, the project is financially unfeasible and should be rejected.

PBP or ‘Payback Time Period’

It is the "estimated number of years required to recover the initial investment" (Mian, 2002) and is abbreviated as "PBP" for "projected breakeven point". The breakeven year is the year in which the total amount of money coming into the organization equals the amount that is leaving the organization as a result of the project. This economic criterion is seldom used alone as a choice criterion due to its low efficacy. A project's "discounted payback period" is the time it will take to earn back the original investment when interest is taken into account. When evaluating a project, this economic factor is taken into account last.

When calculating the discounted PBP, the time value of money is taken into account with the discounted cash flow method (DCF): "the payback period is then the cumulative time (each year with negative cumulative net cash flow from time zero) to a point between the negative and positive net cash flow" (Mian, 2002). The PBP is crucial because it provides a quantitative assessment of the duration over which a firm has committed its capital. While the PBP does not provide information on a project's profitability, knowing what comes after it allows the organization to realize all of the benefits it can.

Brealey et al. (2011) found that "the payback rule states that a project should be accepted if it’s payback period is less than some specified cut-off period." In other words, the time it takes for the business to turn a profit after investing initially ought to be minimal. For making decisions, the PBP is based on the principle that, all else being equal, the shorter the PBP, the lower the risk exposure, and vice versa. PBP has been deemed inferior to other economic indicators due to its various shortcomings (Mentari and Daryanto, 2018).

2.3.2 Meta-Modelling

Using meta-modelling, regression analysis may be included into the cash flow model. Researchers found that "meta-modelling, a relatively new approach in fiscal system analysis, allows us to understand the interactions between variables and their relative influence using a constructive modelling approach" (Kaiser and Pulsipher, 2004). Meta-modelling is a method that has just recently been brought to this area of research, despite its extensive usage in other fields of study, according to Adenikinju and Oderinde (2010). It has been suggested that meta-models of the linear connections between variables in a fiscal system and economic parameters be used during PSC talks (Hong and Kaiser, 2014). Companies and government departments alike might gain insight from such an evaluation.

According to Adenikinju and Oderinde (2010), there are three steps involved in meta-modelling study: (1) computing economic indicators such NPV, IRR, PBP, NPVGT, and NPVCT; (2) creating meta data series; and (3) doing regression analysis on the created meta data. The first step is to examine how the after-tax cash flow under the existing fiscal framework affects the economic performance of the sector. In the second phase, the meta data is generated, taking into account the specifics of the national taxation system. Finally, regression analysis is used to investigate how the fiscal terms affect the economic indicators.

Anupama (2014) suggests that modelling the cash flow analysis is the initial stage in establishing the meta-model. This allows the study's major variables to be accurately expressed in the form of a model that can be utilized to construct a regression model. Discounted government take (GT) and discounted contractor take (CT) are examples of such variables (Anupama, 2014). Comparable calculations were used by Adenikinju and Oderinde in their research; they included PV, IRR, NPCVT, and NPCGOV. Mentari and Daryanto (2018) utilized PBP, ROI, NPV, NPV index, discounted PBP, and IRR as their analytic variables, whereas Hong and Kaiser (2014) used NPV, IRR, and contractor/government Take.

Stationarity was tested using the Augmented Dickey-Fuller (ADF) unit root test in the work by Adenikinju and Oderinde (2010), and then the series was estimated using the ordinary least squares (OLS) method. The accepted meta-models were analysed using an analytical method by Hong and Kaiser (2014).

In conclusion, the meta-modelling strategy is commonly used to investigate the evolution of petroleum fiscal regimes in PSCs across nations' oil and gas wells. So far, however, no research has used meta-modelling to predict how changes in petroleum taxation under the PSC would affect the profitability of natural gas extraction. As a result, there is now a knowledge gap. One of the purposes of this research is to fill up this informational void.

2.4 Empirical Review

Numerous researchers have examined and analyzed the petroleum fiscal regimes of a number of countries. For instance, Adedayo (2016) compared Nigeria’s and Angola's fiscal regimes; Ghebremusse (2014) compared Nigeria’s, Cameroon’s, and Ghana's; Wahab and Diji (2017) compared Nigeria's fiscal regime before and after the Petroleum Industry Bill; Adenikinju and Oderinde (2010), Isehunwa and Uzoalor (2011), Saidu and Mohammed (2014), evaluated PSC offshore projects in Nigeria; Anupama (2014) assessed India’s.

Slade (1984) examined how a tax policy might affect the supply of a limited natural resource. This was accomplished with the use of a copper manufacturing company's several production profit functions. According to the study's results, taxing natural resources produces major shifts in the extraction processes for obtaining ore and producing iron. The research also reveals that higher output prices and depletion allowances (royalties) improve extraction rates at the outset of the extraction and production process but have the opposite effect later on.

For the UK, Norway, Denmark, and the Netherlands, Kemp (1992) examined the efficacy of fiscal regimes in getting greater revenues from oil fields under scenarios of considerable changes in development costs and output (oil) prices. The research used a financial model to assess the efficiency of the regimes in these nations. According to the results, the British tax system adapts well to shifting input and output costs. Government take level is moderate, and the existing tax structure is progressive, so it is not likely to discourage additional investments in the business. While the system provides a higher rate for government take in Norway, it is regressive and discourages investment in smaller oil fields, especially at a real discount rate of 10%. When considering the effects of fluctuating development costs and oil prices, Denmark's tax structure is progressive. Compared to the United Kingdom, the understudied nations' fiscal systems give a greater rate of government take on investments made under the same conditions. The analysis found that the fiscal system in the Netherlands is regressive in real terms but modestly progressive in nominal ones.

Iledare (2001) used a hypothetical field to analyze how petroleum tax regimes affect the bottom line of exploration and production endeavors. The effect on government take and project economics was studied, and the analysis accounted for fiscal provisions under the JVs and PSCs. The study's results imply that government and E&P corporations get less-than-ideal benefits from working in JVs as opposed to PSCs. E&P economic performance metrics seem to react differently to changes in product pricing, discount rate, installed capacity, and enhanced oil recovery (EOR), according to the results.

Offshore economies and government take were studied by Iledare and Kaiser (2006), who investigated the effect of petroleum fiscal regimes. The cash flow model was analyzed using a meta-modeling strategy, with the calculated regression equation used to establish the causality between input and output variables. A higher commodity price and higher oil profits boost contractors' take, whereas a higher royalty rate and higher taxes reduce it. Reduced contractor take occurs when the discount factor is raised for the contractor or lowered for the government. With a rise in price, cost oil, and profit oil, plus a drop in the corporate discount factor and tax rate, the project's present value grows.

To investigate the impact of government policies on offshore E&P projects, Pulisher and Kaiser (2006) turned to meta-modeling. Case studies examining the impact of different tax structures, such as joint ventures and production sharing contracts, were applied to an offshore field in the Gulf of Mexico and an offshore field in Angola. Iledare's (2006) research indicated that although a 1% increase in the royalty rate has minimal influence on PSCs, it does have an effect on JVs. If the tax rate increases by more than 1%, you may want to revise your expected rate of return and discounted value upwards. The study also provided a framework for distinguishing between progressive and regressive regimes. All signals are as expected, the model fits well, and the regression coefficients are all very significant (except for the government discount component).

Osmunden (1998) developed a model for the dynamic taxation of nonrenewable resources in which there is unequal information about reserves. In a two-period model, it was shown that reducing the area and pace of extraction of non-renewable natural resources is the optimal response to their exploitation because of the stock effect. It was shown that the model skewed the number of extraction periods in response to unbalanced data when the model was expanded by making the final period selection endogenous. Since this compilation weakens when considering examples from a wide range of time periods, it suggests that previous conclusions are less reliable when asymmetric information is considered.

Ghebremusse (2014) compared Nigeria, Cameroon, and Ghana with regards to their petroleum fiscal regimes. The following guidelines were used as inputs in the examination of the structure of various fiscal regimes. State reliance on oil income, the maturity of the country's oil business, the government's fiscal health, and the level of state involvement in the oil industry are all factors to consider.

Prior to and after the PIB, Wahab and Diji (2017) analyzed the competitiveness of Nigeria's fiscal regimes. They understood the importance of well designed and implemented fiscal regimes in attracting investors to a nation. With regards to stability, neutrality, flexibility, and the distribution of production risks among partners, the Nigerian fiscal system was assessed in this research. The research suggests that Nigeria's competitiveness in attracting investment in the industry is negatively impacted by the country's royalty/tax structure, which in turn impacts the profitability indices of petroleum activities in Nigeria.

Adedayo (2014) compared the fiscal regimes of Nigeria and Angola, focusing on the mechanisms put in place to distribute the economic rent generated by oil exports. The study evaluated the fiscal regimes of these countries, including signing bonuses, front loading fees, royalties, state engagement, local content regulations, cost controls, income taxes, profit oil splits, and government takes. Each feature's ranking was determined by how conducive each country's regulatory framework is to luring foreign investment. According to the findings, Angola's fiscal system does not need the payment of royalties or signing bonuses, in contrast to Nigeria's PSC fiscal structure. Despite the fact that both countries have adopted a sliding scale for profit share, the PSC fiscal framework does not impose any additional taxes or price limit excess fee. According to the findings, the PSC fiscal framework in Angola is safer and more progressive than the fiscal system in Nigeria.

Adenikinju and Oderinde's (2010) research on the economics of offshore oil investment projects and production sharing contracts used empirical analysis using meta-modeling, which combined regression analysis with the discounted cash flow spread-sheet model of a petroleum project. Internal rate of return (IRR), NPV, NPVT, and NPVGT are some of the economic metrics used to evaluate petroleum projects. To examine the relationship between these indicators and the oil price, tax rate, royalty rate, government discount, and contractor discount, a regression analysis was conducted. Net present value, contractor take, and government take were all shown to be rather high and positive in the study. The internal rate of return is also higher than the cost of capital and the typical market hurdle rate. The regression analysis demonstrates that a rise in oil price mitigates the impact of other fiscal parameters on the economic feasibility of petroleum projects, while a fall in oil price exacerbates this impact.

Isehunwa and Uzoalor (2011) analyzed the effect of real government take in Nigeria's petroleum industry by contrasting fixed and sliding royalty systems. Their study's findings are supposed to aid decision-makers in Nigeria's oil and gas sector as they mull over whether to adopt a fixed rather than a sliding royalty scale in their joint venture agreements and production sharing arrangements. The research employed the generalized cash flow approach to assess the effect of fiscal terms (royalty, tax, equity share, etc.) using a mix of royalty payment strategies on the profitability of petroleum projects in Nigeria. The study's cash flow model excluded revenue from selling natural gas or condensates in favor of focusing entirely on crude oil. In both the fixed and sliding royalty systems, the study showed that the government take was higher in the JV fiscal regime than in the PSC fiscal regime.

Saidu and Mohammed (2014) analyzed how the proposed petroleum fiscal circumstances will affect investment in Nigeria's upstream oil and gas sector. The purpose of the economic evaluation is to let the authors of the research speculate on how the fiscal parameters proposed in the Petroleum Industry Bill (PIB) would impact the profitability of the project. The study conducted a DCF analysis to determine whether or not the project was worth investing in. The study also made use of NCF, NPV, and IRR as economic profitability indicators. According to the findings, the PIB's suggested fiscal parameters have a detrimental effect on short-term upstream investment in Nigeria's oil industry. Findings from the NCF, NPV, and IRR studies, as well as the fiscal criteria proposed by the PIB, all point to the project's economic feasibility.

The petroleum taxation regimes of Nigeria, Indonesia, and Malaysia were studied in depth by Babajide et al. (2014). The study's goal is to compare and contrast the fiscal systems of the nations that use production sharing contracts. The method used to do the comparative analysis in this research was a survey of the previously published literature. The study's findings imply that the Nigerian petroleum fiscal system should prioritize investment promotion above revenue maximization at the cost of service providers. However, the study concluded that Asia should prioritize exploration spending if it wants to expand its reserves.

Anupama (2014) conducted a thorough investigation on the oil and gas exploration tax system in India. The purpose of the study was to examine the consequences of a potential policy shift that would do away with the complex R factor model in favor of a more transparent revenue-sharing structure. The study employed a meta-modeling approach that integrated a regression model with model-field-based simulated cash flow. Data analysis shows that the study's economic criteria (internal rate of return, NPV of government benefits, NPV of contractor benefits, and NPV of government take) are highly impacted by the fiscal parameters included into the R-factor scale of profit sharing.

Serova (2015) analyzed the petroleum taxation systems of four countries: the UK, Norway, Indonesia, and China, contrasting their incentives and structures. The study's overarching objective is to examine the degree to which firms in the United Kingdom, Norway, Indonesia, and China are able to weather price swings brought on by varying petroleum tax regimes. The study found that countries like Indonesia and China employ a production sharing agreement (PSA), whereas countries like the United Kingdom and Norway use a concessionary fiscal structure. Discounted cash flow (DCF) analysis, a common method for determining the financial viability of petroleum projects globally, was utilized in this study. The study uses the net present value (NPV) and the internal rate of return (IRR) to determine the profitability of the selected field, but the effective royalty rate (ERR) and the savings index (SI) are the primary economic criteria used to compare fiscal systems across countries. The analysis found that the United Kingdom had the greatest NPV and IRR for the project out of all the countries looked at, while China had the lowest. Norway has the world's lowest SI, whereas China has the world's highest. The ERR demonstrates that the PSA regimes in Indonesia and China are front-end loaded, whereas the regimes in Norway and the UK are back-end loaded.

Omoniyi (2021) used real options analysis to compare the fiscal regimes for petroleum production in Nigeria, the United States, the United Kingdom, and Norway. The study evaluated deep offshore fields of varying sizes (small, medium, and big discoveries) utilizing the current fiscal regimes under PSCs and Concessionary arrangements in the aforementioned nations at crude oil prices of $30, $45, and $60. The study found that the United States offered the best investment performance for large oil finds under the lowest oil price regime of $30 per barrel, while the Norwegian fiscal regime offered the best investment performance for small oil finds under the lowest oil price regime of $30 per barrel.

China's offshore production sharing arrangements were modeled in 2010 by Hong and Kaiser. The goal of their research is to use a probabilistic method to assess China's PSCs. Profitability of petroleum projects was evaluated using the discounted cash flow (DCF) technique of economic analysis, and then the research examined the characteristics of the country's fiscal terms using meta-models within the framework of regression analysis. The research found that the government's participation interest and the split ratio had a greater impact on the profitability of petroleum projects than cost recovery and interest rates did.

Njeru (2009) calculated how the profit-share between the government of Kenya and IOCs would change if it were tied to a sliding scale based on daily production volume. To optimize government income and assure a fair return on investment for IOCs, the study conducted an economic analysis of the fiscal regime of Kenya's oil and gas industry. The cash flow analysis used in this research used the economic criteria of undiscounted government take (GT), net present value (NPV), internal rate of return (IRR), operational leverage (OL), and saving index to measure Kenya's petroleum fiscal regime. In addition, sensitivity analysis was performed using the spider diagram to see how different factors affected Kenya's BOPD-based systems. The analysis showed a positive correlation between oil price and NPV and IRR; hence, the government take is unaffected by changes in oil price.

Owusu-Ansah (2008) conducted a study on financial decision fundamentals in Ghana’s oil and gas resources, which is a comparative analysis between real options and traditional method. The study adopted the traditional approach to economic analysis for project evaluation that makes use of economic indicators of NPV, IRR, payback period (PBP), decision tree analysis (DTA) and also adopts the real options methodology for choosing the most profitable business amongst numerous viable projects. The outcome of the study revealed that the project is not economically viable as shown by the result of the economic indicators of the traditional method. On the other hand, the project is viable given the result of the real option analysis.

For the years 2019 through 2037, Mentari and Daryanto (2018) analyzed the financial viability of oil and gas projects in Vietnam to determine whether or not to invest in the country's oil and gas sector. To assess the sector's potential to boost Vietnam's income stream, this research aims to conduct an economic analysis of the PGN Project Diversification of the Project Nam Con Son 2 Phase 2 natural gas pipeline. The capital budgeting model technique was used to perform the economic analysis and sensitivity analysis on the project. The research looked at the project's PBP, ROI, NPV, NPV index, discounted PBP, and IRR as economic indicators. This analysis demonstrates that the NPV and NPV index are both positive and meet the criteria for a successful project. Similar to how the project's IRR exceeds the 12% cost of capital level, the project's ROI also exceeds the 10% investment returns threshold, ensuring the project's sustainability. Finally, the project has a discounted payback period of less than 8 years and an all-in payback period of less than 6.7 years. Finally, the oil and gas industry has the potential to bring in massive revenue for the country, proving that the project is economically viable.

Similarly, Merzi and Daryanto (2018) used the City Gas project in Indonesia as a case study in their feasibility analysis of the Perusahaan Gas Negara (PGN) project for the years 2018 through 2038. The goal of this project is to conduct an economic analysis of a natural gas project that distributes gas to homes in the provinces of Serang, Bogor, and Cirebon to determine the feasibility of the venture and the potential it has to create cash for the government. Using the capital budgeting model, the research compared government-regulated prices to market prices using the economic indicators of PBP, ROI, NPV, NPV index, discounted PBP, and IRR. All economic parameters having a negative outcome indicate that the project using the government regulated price is not economically viable. However, the project that adopted market-based pricing did succeed. The initiative is lucrative, as shown by all economic indices.

Conventional oil production in Indonesia was the subject of an empirical study by Daryanto and Primadona (2018), who examined the country's fiscal policy as it pertains to production sharing contracts. The purpose of the research is to assess the potential of oil investments in Indonesia and, more specifically, to analyse the terms that may be implemented in the PSC fiscal petroleum system of the nation. Economic analysis and sensitivity analysis of the crude oil project were conducted using the capital budgeting model indicators of PBP, NPV, IRR, and weighted average cost of capital (WACC). Under a controlling cost recovery and oil price of US$50/barrel, the analysis reveals that the PSC fiscal regime is most appealing when the profit oil split is 50% between the government of Indonesia and its contractor.

In conclusion, the empirical literature assessment undertaken in this research reveals that most studies used the capital budgeting method to investment analysis when assessing the various national fiscal regimes studied. NPV, IRR, and PBP are the most often used economic metrics. This technique has become the standard for calculating the financial viability of oil and gas projects and for determining where to allocate capital.

2.5 Theoretical Framework

The economic rent theory by David Ricardo is the underlying theory adopted in this study for the design of a petroleum fiscal tax system.

2.5.1 The Economic Rent Theory

The concept of economic rent was first discussed by Classical economists: David Ricardo; Stuart-Mill and Alfred Marshall. David Ricardo defined economic rent as:

"*That portion of the produce of the earth which is paid to the landlord for the use of the original and indestructible powers of the soil"*.

In Ricardo's view, rent is a producer's surplus and is only attributed to land as against other factors of production.

Modern economic rent theory on the other hand generalised the term 'rent'. The modernist School of thought posit that rent is an economic surplus paid to any factor of production for the purpose of keeping the factor in a particular use. This surplus or rent paid is believed to be above its transfer earning which is the price a particular factor of production commands in order to not be used for a different purpose.

The main divergence between the Classical and Modern School of thoughts on economic rent is that the classicalists believe only land can command rent while the modernists posit that all other factors of production can command economic rent as they all have alternative uses.

Modernists believe that other factors of production such as labour, capital and entrepreneurship are paid surpluses because there is a difference between the actual value or price paid to keep the factor in particular use which is the transfer earning and an additional price or value paid to the factor for not being used for alternative purposes.

Assumptions of the Ricardian Theory:

The classical theory of economic rent by Ricardo is based on the following assumptions:

1. The rent any land commands is dependent on the indestructible and original powers of the soil. This means Ricardo bases the differential rent of land on fertility or situation of the plot of land in question.

2. The law of diminishing marginal returns applies to the cultivation of land. Here, the produce from less fertile lands differs from more productive lands even though the cost of production is the same.

3. The supply of land is fixed. This view is based on the perspective of land mass alone.

4. Land is a gift of nature and does not have any price or cost of production. The assumption therefore is that any payment made for land is a surplus as no cost of production is incurred in it.

This theory was propounded around the era of the First World War. At this time, Ricardo assumed the only use for land was to grow corn and as such the available land for this purpose is fixed, as shown in the figure below. This meant that the price of land was totally determined by the demand for land to grow corn.

Thus, in the said period –World War I era, it was the price of corn that drove the demand for land and in turn increased the price of land, not vice versa. This assumes that land has only one use, when in reality, land has alternative uses and its demand is therefore elastic –this means the said land can be used for other purposes besides growing corn and as such commands a transfer price for not using the land for alternative uses.

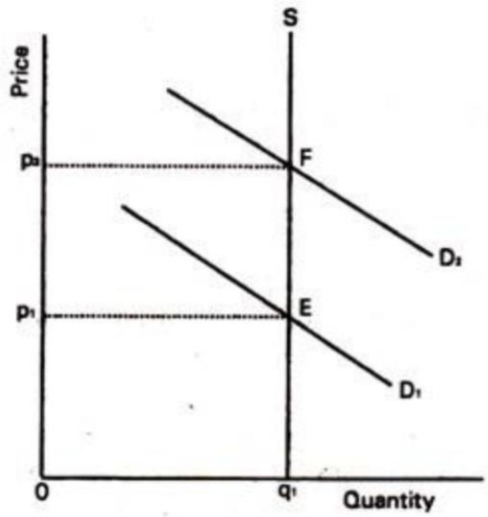


Fig. 2.8 Earnings of a Factor in Fixed Supply

2.5.1.1Economic rent in the context of a Rentier State

The Classical view of the theory of economic rent has been discussed above, in this section, the theory of economic rent as a concept in a rentier state, as introduced by Hossein Mahadvy is discussed.

Mahadvy (1970) defined a rentier state as a country which receives substantial amounts of economic rent regularly. A rentier state is also defined as a country which depends on rent from external sources such as activities from crude oil instead of domestic sources of rent from surplus production from its citizens (Anderson, 1990).

Koru (2002) claims that countries with the features of a rentier state are predominantly from the Middle East and North Africa while Anderson (1990) includes Nigeria and Venezuela as rentier states alongside the countries of the Middle East and North Africa. This is because of the Oil boom in the 1970s which brought about a neglect of other sectors of the Nigerian economy especially, agriculture for the economic benefits crude oil development offered.

2.5.1.2 Application of Economic Rent in the Petroleum Industry

This subsection highlights the similarities in treatment between the mining industry and economic rent as noted by Tilton (2003).

1. The raw material extracted in these countries such as Nigeria are owned by the federal government and as such should command a higher return in form of taxes to the government than what other industries are charged. This discusses the concept of surplus.

2. Mineral resources diminish in quantity. This means the resource is non-renewable, as such; quantities extracted today cannot be extracted for the benefit of future generations tomorrow and as such needs a compensation for that fact.

3. The return on investment of many ventures are not commensurate with the capital deployed or invested, this makes for the question why returns from mining are

shared with a balance of interests from the mining company and the host government.

The issues highlighted in this subsection in relation to their application in the petroleum industry are further discussed below:

2.5.1.2.1 The Scarcity Rent Concept

Petroleum is a finite resource. This means its consumption now makes future consumption impossible. Hotelling (1931) recommends that the price of any exhaustible commodity should be placed above the commodity's marginal cost of production.

An illustration of this concept is that for example, if there is going to be a drop in the global petroleum output for next year, maybe due to some unfavourable circumstances with top petroleum producers such as wars, this will mean the forecasted reduction of output will lead to a speculative increase in the price of crude oil next year. As such, it will be beneficial to producers to produce and store their crude oil now with the aim of selling this produce at the higher market price forecasted next year. On another end, the producer can choose to not produce his resource now until next year when the prices have risen. In order to keep production activities going without interruptions, adequate compensation needs to be given to petroleum producers which are commensurate with potential earnings from projected increases in petroleum price. This compensation which is above the marginal cost of producing the crude oil is the economic rent.

2.5.1.2.2 Differential Rent Concept

David Ricardo posited that the difference in fertility of agricultural lands is a reason for a difference in economic rent paid on the class of land, as more fertile land requires lesser amount of resources to produce great yields compared to lesser fertile lands. In relation to the petroleum industry, this can be illustrated as thus: the difference in the subsurface structure of lands suggests their potentials in the possibility of finding petroleum reserves in a particular land. A land with good geophysical subsurface properties which produces crude oil with low sulphur content –light crude oil will be of higher value than a land which produces crude oil with high sulphur content –heavy crude oil. This is because it is more technical and expensive to refine crude oil with high sulphur content that its counterpart. As such, lands which house petroleum reservoirs containing light crude are of more value and command higher prices than those which contain the heavy crude blends. This difference in price illustrates the difference rent concept.

2.5.1.2.3 Quasi Rent Concept

Firms tend to develop innovative means and make strategic investments in order to reduce costs and enjoy better profits. In the petroleum industry, firms request rewards for being innovative in operations and investments. Investments in exploration in a country can be significant and firms usually request for incentives or rewards for taking such investment risks. This reward is referred to as quasi rent.

At the development or production stage of a petroleum field or asset, a company might introduce more strategic and innovative measures including petroleum trainings of their staff in order to efficiently produce these petroleum resources at a lower rate. The market for crude oil is very competitive and the produce is sold at a market rate. The difference between the average variable cost of production by a particular company and the market price of the crude oil produced is the quasi rent which the firm is entitled to as a reward for its innovation and efficiency.

2.5.2 Petroleum Fiscal Regime Design

The host Country (in this case- Nigeria) is one with natural petroleum resources which the government as representative of the people holds in trust, while the International Oil Companies have technology, Capital and experience which creates an opportunity for both parties to negotiate and exploit the resources with mutual benefits to the parties involved. The fiscal regime is therefore a careful balance between the objectives of both the Government and the investing Company.

The goals of the host government and investors in maximizing profits from natural resource exploitation are aligned under fiscal regimes. The host government and the investors both have different interests and goals. In order to increase treasury net revenues, host governments prioritize optimizing project value above project volume. Governments in host countries often have broader socioeconomic goals, such as the hiring of locals, the sharing of technological know-how, and the improvement of physical infrastructure. On the other hand, oil corporations and investors seek for nations and investments where the return on capital is proportional to the risks of the project and consistent with the long-term objectives of the company (Tordo, 2006).

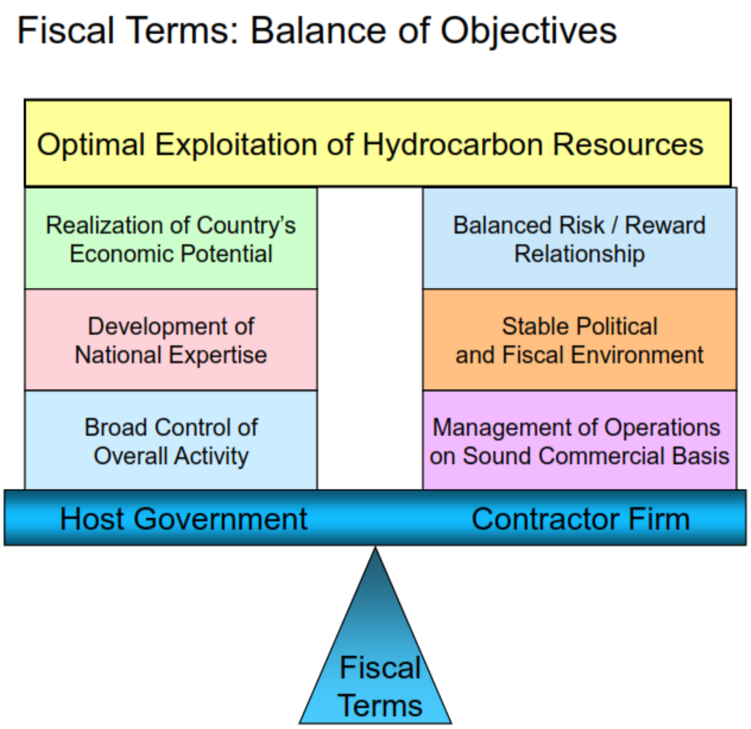


Fig. 2.9. Balance of fiscal objectives/interests between host government and IOCs

Source: Tordo, 2006

The following are features of a sound fiscal system from the perspective of the host government:

1. It ensures a predictable and stable fiscal revenue-flow from projects, which helps the country's macroeconomic goals;
2. Allows capture of greater revenues during periods of high profits;
3. Avoids the introduction of distorting effects through fiscal instruments;
4. Is neutral and encourages economic efficiency as a yardstick.

An attractive fiscal regime permits investors on the other hand to:

(a) Pay as little as possible in up-front, non-profit-sensitive taxes;

(b) Return profits to shareholders in their home countries, and

(c) Operate in an environment where policies are clear and consistent and are based on internationally recognized industry standards and the rule of law.

Stable and neutral fiscal regimes are recommended and implemented in an effort to bring these divergent objectives into harmony.

Several Tax and Non-Tax instruments can be used in designing fiscal regimes to construct a framework for efficient allocation of resources from petroleum production between a state and other stakeholders. These tools might be sector-specific or generalizable. The timing and size of revenue allocations are often adjusted via fiscal incentives and allowances for petroleum projects. These are implemented to attract investors, modify petroleum asset structures to account for their particular characteristics, or steer investors in a certain direction in order to achieve public policy goals (Tordo, 2006).

2.5.2.1 Fiscal Regime Competitiveness

Fiscal regime competiveness is also a feature of good fiscal regime design. This feature is based on the premise that economic resources such as petroleum are finite, financial and technical resources required to harness this resource are also limited in supply. As such, investors are always on the look for better regions to invest these resources in order to maximise benefits for their stakeholders. To attract such investments, host governments need ensure that their fiscal regimes are not only competitive but dynamic keeping the need for stability and neutrality in perspective.

Table 2.3 shows the comparative rates of different fiscal provisions for leading African petroleum producers.

An analysis of the fiscal regimes of these leading African petroleum producers is summarized further using evaluative features such as progressivity/neutrality, stability, flexibility and risk-sharing to compare the competitive nature of these regimes. Table 2.4 below is a representation of the data collected.

Table 2.4. Summary of Fiscal features in selected African Countries

	Front Loading fees	Royalty (%)	Local Content	State Participation	Cost recovery (%)	Income tax (%)	Profit Oil (%)
Algeria		**0-20**		**51**	**100**	**26**	**85**
Angola		**10-20**		**50**	**50**	**70**	**80-90**
Egypt		**10**		**Above 50**	**Not specified**	**40.55**	**Negotiated**
Equatorial Guinea		**13**		**20-50**	**100**	**35**	**Negotiated**
Libya		**12.5**		**Above 50**	**100**	**65**	**Production Sliding Scale**
Nigeria		**20**		**60**	**99**	**65-85**	**30-75**

Source: Author's Compilation

Table 2.5. Comparison of the evaluative features of fiscal regimes in Selected African Petroleum producers

Fiscal Feature / Country	Progressivity	Stability	Flexibility	Risk Sharing
Algeria	Quasi-progressive	Quite stable	Low Flexibility	High Risk Sharing
Angola	Progressive	Stable	Low Flexibility	High Risk Sharing
Egypt	Contract Specific	Contract specific	Flexible	Contract specific
Equatorial Guinea	Quasi-progressive	Stable	Flexible	High Risk Sharing
Nigeria(Pre-PIA)	Quasi-progressive	Quite stable	Low Flexibility	Higher Risk Sharing
Libya	Regressive	Quite stable	Low Flexibility	High Risk Sharing

Source: Author's Compilation

2.5.2.2 An Ideal Fiscal System

In designing an effective, competitive and efficient petroleum fiscal system, certain criteria need to be fulfilled. An ideal fiscal system should:

- Ensure a secure business climate with minimal sovereign risk.
- Not promote unnecessary speculation
- Allow for a more equitable distribution of risks and rewards among participants under varying economic conditions and levels of optimism
- Avoid complexity and limit administrative bureaucracy within the industry
- Encourage robust competition and market performance

For National Oil companies to achieve this, a summary of proposed fiscal elements and theoretic boundaries for Production Sharing Contracts are given below in fig. 2.9:

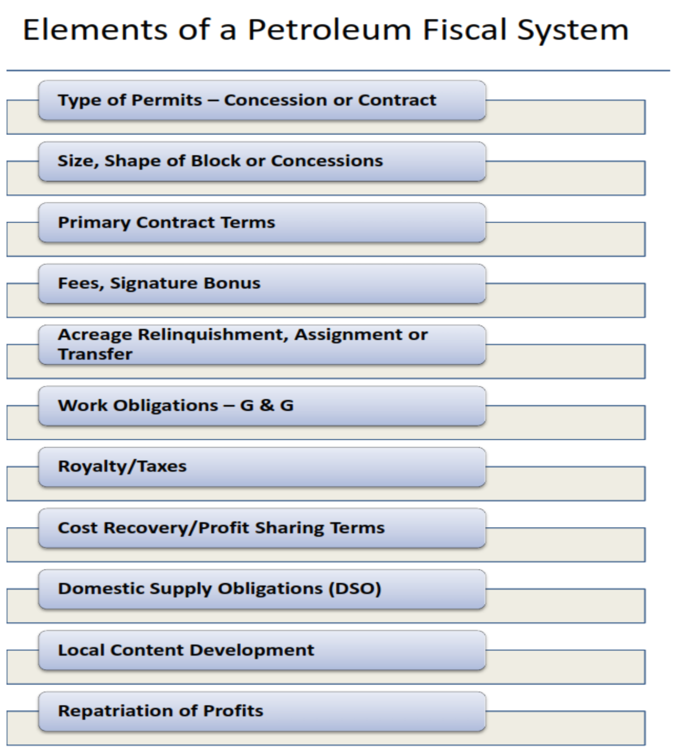


Fig 2.10. Elements of an ideal fiscal system

Table 2.6. Fiscal Term Options and Ideal Provisions

FISCAL TERM	FISCAL OPTIONS or RANGE	IDEAL PROVISION
Type of System	Concessions/ PSCs/SCs	PSC
Allocation Mechanisms		Sealed bids on specific blocks and direct negotiations
Work Programs		Biddable or negotiable
Duration and Relinquishment		Asset to be relinquished if commercial production is not on stream in 10 years post-award.
Signature Bonus		Nil
Production Bonus		Production start-up bonus $1 MM
Royalty		Nil
Cost Recovery Limit		50% (Unrecovered costs to be carried forward)
Profit gas split		Biddable
Taxation		To be paid by the concessionaire from profits obtained
Government participation		10% carried through confirmation of discovery
Custom duties		Exempt
Dispute resolution		Binding international arbitration
Ring-fencing	Yes/ No- (provision for consolidation of liabilities between assets)	No- No consolidation allowed

Source: Author's compilation; Johnston, 2003.

2.5.2.3 Building an Efficient Fiscal Regime

In building an efficient fiscal system, several interests are put into perspective; key of which is whether or not the interests of the Host Government and the oil companies are aligned. The unique traits, concerns, and ambitions of each nation's boundaries shape its policy, strategy, and tactics in the global war for capital and technology (Johnston, 2003). The Niger-Delta Basin, in Nigeria, is defined by its proximity to the Atlantic Ocean and its known resources of approximately 208 trillion cubic feet of natural gas and 37 billion barrels of oil (OPEC, 2023).

With an increasingly competitive worldwide market, Nigeria's federal government must offer a competitive fiscal regime as a guide for enterprises in the sector if the country is to see the expected push toward creating a viable natural gas industry. Concerns about gas flaring and gas monetization plans in the nation will be successfully addressed.

Investors should not just watch for regions with better odds of technological achievement, but also places with higher commercial success. To create a fiscal regime that is both neutral and efficient—one that balances the Nigerian government's push to monetize gas as a quick way to diversify its revenue stream with the need to create a regime that is competitive on the global stage—serious care is taken to ensure that investors' interests are protected.

2.5.2.3.1 The Savings Index

In fiscal regime design, the need to keep costs down is an essential consideration. An efficient fiscal regime should amongst other interests clearly define the 'what-goes-to-who' question. Governments want costs to be kept down because it guarantees a sizable 'take' from economic profits while IOCs will have the incentive of keeping costs down and not over spending or cheating on costs if they believe they will be getting a reasonable portion of a dollar saved on costs. There is therefore an alignment of interests by both parties (the NOCs and IOCs) when there are good incentives for keeping costs down- the degree is however determined quantitatively through the Savings Index Computation.

Theoretically, a negative savings index for IOCs is regarded inefficient as it encourages 'gold-plating'. Here, IOCs are encouraged to spend more than necessary as they make more money during deductions/cost recovery by spending more during operations. In current regimes, this is very rare as they (the IOCs) are not that inefficient.

Fiscal systems with low savings index on the other hand, encourage IOCs to cheat on costs by over-invoicing expenses made, or falsely inflating costs. This is done because the IOC will earn more when they are unsupervised and believe they can get payments for costs not incurred through over-invoicing or an outright inflation of costs incurred since they will recover whatever bookable cost is incurred.

The issue of IOCs cheating on costs is however not as clear-cut as claimed because it will have to involve other partners which in most cases include a division of the NOC. Host governments have therefore devised measures of checking, supervising, controlling and monitoring costs/activities of contractors and/or operators through the following means:

- Budgeting- Authorization for Expenditures (AFEs): Here, contractors present their intended costs which are scrutinized by the panel which in most cases the NOC chairs.
- Work Program and Development Plan approval rights.
- Procurement rules in PSCs and JVs
- Auditing rights.
- Third party auditing.
- Government Working Interests and other partners who serve as watchdogs on operations.
- Benchmarking- host governments have a database of costs from best-in-class operators in-country.

2.5.2.3.2 Production Sharing Contracts (PSCs)

PSCs are widely regarded as the preferred alternative to concessionary and service systems. This is because PSCs give extended government ownership and greater sovereign control over assets or licenses. The mechanical and financial differences between these systems might be negligible but government-takes under PSCs far outweigh that for a typical R/T system (Johnston, 2003).

For governments, the PSC system is a way of transferring the risks of exploration completely to the investing company. This of course is the area of greatest risk in the industry. The Nigerian government also uses PSCs as a means of “clearing” the JV cash call obligations they are faced with. IOCs on the other hand accept the sole risk of exploration activities under PSCs mainly because they want the least government interference in the riskiest part of the business, they believe their expertise, experience, technology and capital, will get them through this risky phase and with clear upfront negotiations that will balance risk and reward, they are confident they can manage the viability of the venture at hand.

This therefore is the attraction for both parties – Government and IOCs – in a way; the PSC aligns the objectives of both parties better than other fiscal systems, which is why it is popular in many regions, particularly in deep-offshore prospects where technological capacities and risks are at ultra-high levels.

2.5.2.3.3 Allocation Mechanism

To governments and for market efficiency, competitive bidding is preferred. Companies on the other hand prefer direct negotiations. An ideal system should consider sealed bids in winning acreage licenses but on the basis of profit oil split bid, but would also make provisions for direct negotiations for certain oil blocks at the discretion of the National Oil Company. In addition, work programs would also be biddable or negotiable. By providing a profits-based bid item for acreage allocations, it provides sustainable flexibility to a large extent and removes the burden of fiscal marksmanship from the government (Johnston, 2003). Fiscal marksmanship here refers to the requisite knowledge or information of what the market can bear under various economic and technical conditions.

2.5.2.3.4 Work Program

In fiscal systems where work program poses an influential term in winning licenses, these bids effectively serve as signature bonuses. This is because as technical personnel of the companies commit and propose technically-appropriate work to be done, the extra work commitment shown in their bid in order to win the acreage serves as a signature bonus. While technical personnel would certainly debate what an appropriate amount of work might be, they generally agree that a competitive work program bid must exceed it (Johnston, 2003).

2.5.2.3.5 Duration and Relinquishment

Petroleum projects have a long life cycle because of their complexity and need careful planning and management. Companies are in the best position to determine the length of a petroleum project; this should be included as a bid term.

It is common practice to divide the whole exploration time of 6-8 years into three phases, with each subsequent phase requiring the concession of 25% of the original region in a continuous block of land. After then, any land not directly tied to the research and development of discoveries must be given up. The oil production cycle should last at least 25 years. In addition, many nations typically allow a market development period of 5-10 years for gas finds. Areas without a natural gas market or infrastructure may have to wait as long as ten years (Johnston, 2003).

2.5.2.3.6 Bonuses

Signature bonuses are seen to be regressive and discourage investments especially for small companies about to get into the exploration phase. About 40% of countries use this term but have a negative impact on exploration economics as companies prefer to spend their limited exploration funds on data acquisition (Johnston, 2003).

Production and start-up bonuses are paid when production begins as they are only paid if a discovery is actually made and then developed. These are preferred to signature bonuses as they rest on the reward side of the project-life cycle equation and help governments fund the initial impending regulatory workload.

2.5.2.3.7 Royalty

Royalties are common place in most fiscal systems, though they are also regressive. They only guarantee a share of production to the government in every accounting period, but that can equally be achieved more efficiently through cost recovery limits.

2.5.2.3.8 Cost Recovery Limit

To guarantee that the government receives its fair part of output in each accounting period while being less retrogressive than royalties, one solution is to combine a cost recovery cap with a profit oil split similar to royalties. However, the efficient rate and ERR should be set by oil companies through the biddable/negotiable profit oil (or gas) split, rather than the global average recovery limit of 63 percent.

2.5.2.3.9 Profit Oil (or Gas) Split and Tax

A profit oil or gas split will be better determined by profit based metrics such as R factor (pay-out formula) or IRR thresholds (ROR systems).

Unlike the R-factor and ROR systems, production-based sliding scales are insensitive to changes in oil prices, allowing the government to keep a larger part of the profits at higher production rates. This means that, theoretically speaking, R factor and ROR systems are more adaptable and efficient. Even though over 75% of PSCs worldwide prefer the production-based sliding scale, this is not the case. By making profit oil split a biddable term, money left-on-the-table and/or winners curse, a phenomenon of competitive bidding would accrue to the benefit of the government. This is very efficient as the oil companies and thus the market determines what the industry can bear.

It is recommended that taxes be deducted from the state's allocation of goods and services. Here, all monetary details are written into the agreement, and the contractor is protected from any changes in tax rates made by the government. When correctly arranged, these taxes in lieu may be credited to the oil firm's home country tax liability just as if the corporation had paid them directly.

2.5.2.3.10 Government Participation

For several reasons, including diminished entitlement, excessive government involvement in technical and operational committee meetings, and diminished corporate take, this term, with the government as a working interest member of the contract group, remains unpopular with oil firms. Incorporating a modest direct interest (let's say 10%) would not significantly alter the project's economics, but it would aid in the education of key government personnel and provide new perspectives on how the sector operates.

The NOC has the opportunity to re-enter and acquire a working stake in a discovery in around half of the nations. In these nations, NOCs typically have a 30% working interest. In many cases, NOCs may use their production share to cover all or part of the cash calls associated with their working interest. As a result, the possibility of the NOC being unable to satisfy cash calls is mitigated (Johnston, 2003).

2.5.3 The Discounted Cash flow (DCF) Analysis

This is a technique for determining the worth of a future financial benefit when valuing a project, asset, or business. According to this theory, money received now is more valuable than money obtained later. The reason for this is because if one invests the $1 they get today at a rate (i=interest rate), they will eventually have more than the one dollar they are owed. Investors need a justification for their funds that are to be tied down with returns coming in fractions over the life of the project, so the time value of money concept cannot be overemphasized due to the long term nature of petroleum projects (typically 20 years or more). To arrive at their current values, all expected cash flows into the business are discounted by an amount equal to the cost of capital. The NPV of a project is calculated by adding together all of its expected cash inflows and outflows. Mathematically, the DCF can be represented as:

$$NPV = \sum_{t=0}^{T} \frac{CF_t}{(1+i)^t} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad 2.1$$

Where:

NPV = is the discounted cash flow from the proposed project

CF = is an expected inflow or outflow of funds from the project

I = refers to the interest or discount rate. It is the compensation paid to an investor for tying up funds in a project.

T = refers to the time period in an investment or a project.

2.5.3.1 Economic Returns Metric Calculations

Project assessment always begins with the calculation of economic indicators of profitability, such as Net Present Value (NPV), Internal Rate of Return (IRR), and Profitability to Investment Ratio (PIR).

The Present Value is given by (PV(f,F)) for a made-up field (f) and fiscal regime (F).

To calculate a project's NPV, subtract the sum of all expected cash inflows from the sum of all expected cash outflows for the time period in question.

$$PV(f,F) = \sum_{t=1}^{k} \frac{NCF_t}{(1+D)^{t-1}} \quad \text{……………………………………..} \quad 2.2$$

Internal Rate of Return: is a way to measure the success of an investment's return on capital. The word "internal" is used since the statistic does not take into account the risk-free rate, inflation, the cost of capital, or the inherent financial risks associated with an investment. Vector NCF(f) Internal Rate of Return =:

$$IRR\ (f,F) = \{D/PV(f,F) = 0\} \quad \text{…………………………} \quad 2.3$$

Where D is the discount rate that equates the present value with zero.

A profitability Index (PI) or profit investment ratio (PIR): measures the efficiency or productivity of each unit of capital invested in a project. It is also the ratio of payoff to investment of a proposed project. This can be calculated as:

$$PI\ (f,F) = \frac{PV\ (f,F)}{PV(TC)} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad 2.4$$

Capital budgeting uses relative indicators such as rate of return and profitability index to evaluate projects, whereas present value gives an absolute estimate of the project's net worth to the contractor. Economic values should be understood in connection with other system measurements and decision factors rather than as a standalone indicator. In most cases, many economic indicators are needed to provide an accurate prediction of a project's economic feasibility and performance. The percentage of derived profits from a petroleum project shared between the government and contractor is referred to as "Parties Take" or "Take". This is a fiscal statistic as opposed to an economic measure and thus is generally treated with more importance by the host government. 'Parties Take' does not provide a direct indication of the economic performance of a field rather; it reflects the fairness or harshness of a regime in relation to fiscal provisions. This statistic is derived as follows:

The total cost in $year_t$, TC_t is defined as:

$TC_t = CAPEX_t + OPEX_t$, ……………………………………… 2.5

And the total profit is the difference between the gross revenues and total cost:

$TP_t = GR_t - TC_t$. ………………………………………..……. 2.6

If the total profit in $year_t$ is written;

$TP_t = CT_t + GT_t$, ……………………………………………….. 2.7

Then the government and contractor take is computed as;

$CT_t = TP_t – ROY_t – TAX_t$ = Contractor Take in $year_t$, ………… 2.8

$GT_t = ROY_t + TAX_t$ = Government Take in $year_t$. ……………. 2.9

2.6 Research Gap

There is a paucity of research in natural gas fiscal systems and regimes for the development of this resource in Africa. This is so because most oil producing nations in the continent treat natural gas as a by-product of crude oil and do not have separate treatment in tax terms for natural gas development. It is an objective of this study to build an independent fiscal regime to guide investors in the development of natural gas in associated gas fields in Nigeria.

The study explores the capital budgeting approach in obtaining deterministic estimates of profitability indices using the widely accepted DCF technique and explores a probabilistic approach using a sensitivity analysis to determine the responsiveness of outputs to inputs data of the projects. This approach explores the advantages of the capital budgeting and meta-modelling approaches. To the best of our knowledge, a probabilistic approach has not been utilized in conducting an economic evaluation of deep offshore natural gas projects under PSCs in Nigeria.

CHAPTER THREE

METHODOLOGY

3.1 Preamble

This chapter discusses the research methodology adopted in this study, the sources of data utilized, the empirical model specification and estimation technique and the sample of deep off shore associated gas fields under PSC in Nigeria from which the selected field utilized in this study was chosen.

3.2 Data Sources and Method

For the purpose of this study, secondary data of an Associated-Gas field were obtained. It is the hope of this study to gather reliable data on fiscal instruments such as signature bonus, Royalty, direct and indirect taxes, NDDC Levy, Cost and profit oil, government and contractor takes from an operating gas field under a subsisting Production Sharing Contract in Nigeria.

An un-named field with estimated reservoir-production life of 22 years (2005-2027) was used as a case study. This field is an associated gas field in deep waters operating under the current PSC fiscal regime. Provisions made for gas projects in the PIA (2021) such as royalties, profit sharing; production allowance, etc. were collected and compared with the proposed regime for natural gas production in Nigeria.

3.3 Estimation

This study was conducted using secondary data obtained from an existing associated gas field in Nigeria. An economic analysis of the fiscal provisions in the PIA for natural gas development would be conducted using variables such as Capital Expenditures (CAPEX), Operating Expenditures (OPEX), Royalty, direct and indirect taxes, cost and profit gas, NDDC levy, etc.

Economic and financial packages were used in building a model for the evaluation of the Gas field for development using DCF analysis. This would inform our decision and thus design in building a fiscal model for Associated Gas producers under PSCs in Nigeria.

3.3.1 Empirical Model Specification

The DCF model for this study is therefore stated as:

$$DCF_t = REVENUE_t - CAPEX_t - OPEX_t - ROYALTY_t - NDDC_t - EDT_t - CITA_t \ldots\ldots \qquad 3.1$$

Where:

DCF is the discounted Net Present Value of funds from the project

REVENUE is the product of natural gas prices and volume of natural gas produced annually

CAPEX is the capital expenditure

OPEX is operating expenditure

Royalty is the royalty rate charged on production by the government

NNDC is the levy charged by the government for the development of the Niger-delta region in Nigeria.

EDT is the education tax levied on producing companies

CITA is the company's income tax

Comparison of Associated Gas fields –deep offshore Nigeria:

The Table 3.1 shows the estimated production volumes of natural gas from some of the largest named fields in terms of natural gas production volumes -which are deep offshore Associated Gas projects under PSCs in Nigeria. These selected fields are based on random sampling from AG PSC projects with available data from existing contractual arrangements with the federal government of Nigeria.

From Table 3.1, the minimum production volume from an asset is 21BCF and the maximum production volume from an asset is 3,060 BCF. A field of average production size is picked from the samples above as the hypothetical field for the study. These assets contained in Table 3.1 have varying cost structures which are largely dependent on the technical features and considerations of the project and are therefore not uniform. Similar studies conducted using a hypothetical field for analysis of project economics include: Mian (2004), Iledare (2004), Isehunwa and Uzalor (2010).

The evaluation of on-stream AG gas fields under a PSC in Nigeria was conducted to ensure data and variable estimates are real. This will help in producing findings from the study which are robust and applicable to the realities of the Nigerian petroleum industry.

Table 3.1: Sampled Associated Gas fields –Deep Offshore Nigeria.

S/N	NAME OF FIELD	OPERATOR	PRODUCTION FORECAST OF GAS VOLUME (BCF)	REMARK
1	Abo	NAE	21	OML 125- Started Production In 2003
2	Agbami	STAR DEEP WATER	509	OML 127- Started Production In 2008
3	Akpo	TOTAL E&P	2,829	OML 130- Strarted Production In 2009
4	Bonga	SNEPCO	1,645	OML 118- Started Production In 2009
5	Erha	EXXON	3,060	OML 133- Started Production In 2006
6	Usan	TOTAL E&P	1,775	OML 138- Started Production In 2012

Source: Author's Compilation

CHAPTER FOUR

DATA ANALYSIS AND DISCUSSION OF FINDINGS

4.1 Preamble

This chapter is broken up into many pieces. The first paragraph of Chapter 4 is the introduction of the chapter. In Section 4.2, we examine information from a PSC-regulated offshore associated gas field in Nigeria. In Section 4.3, the proposed tax structure for natural gas production in offshore Nigeria is presented. Section 4.4, presents the results of a comparison between the fiscal provisions of the Petroleum Industry Act (PIA) 2021 and the fiscal regime developed for this study. Section 4.5 contains the presentation and discussion of the study's findings.

4.2 Analysis of the Discounted Cash Flow Model

Deterministic Analysis

The cash flow analysis starts from 2005 when commercial production of oil and gas from the hypothetical field began. Capital costs for gas is $1,100 million. Capital costs per barrel of oil equivalent for gas is $5.83/boe (in 2019) terms. Operating costs for gas is $417 million, while operating cost per barrel of oil equivalent is $2.21/boe (all in 2019 terms). The Production profile of the asset and cost structure is computed in the cash flow model show in Table 4.1:

The production profile of the project is shown in Figure 4.1 below:

From the deterministic model in Table 4.1, projected revenues are obtained from production volumes over time multiplied by the forecast price for natural gas. These revenues are subjected to provisional deductions proposed in the fiscal regime in the following section.

PROJECT CASHFLOW																									
DESCRIPTION	UNIT	TOTAL	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Gas Price	$mscf																								
Production volume	Bcf	1163	0	0	0	113	130	135	80	114	65	31	129	75	60	60	40	26	22	19	17	14	13	11	9
Revenue	US$M	1357.113975	0	0	0	113.8169	134.2133	142.8597	86.77406	126.7444	74.07318	36.21039	154.449	92.04083	75.47348	77.36032	52.86288	35.2199	30.54649	27.04058	24.79906	20.93333	19.92404	17.28027	14.49187
COSTS																									
Opex	US$M	161.7472328	0	0	0	15.71577	18.08009	18.77547	11.12621	15.85484	9.040043	4.311405	17.94101	10.43082	8.344655	8.344655	5.563103	3.616017	3.059707	2.642474	2.364319	1.947086	1.808009	1.529853	1.251698
Capex	US$M	426.4973453	67.06496	75.22631	101	21.64003	24.7028	27.94095	12.06577	16.78371	10.37418	5.154052	18.55459	10.77065	8.338991	9.634112	6.277371	4.228966	3.700345	3.039569	0	0	0	0	0
Royalty	US$M	33.92784938	0	0	0	2.845423	3.355332	3.571493	2.169352	3.168609	1.85183	0.90526	3.861225	2.301021	1.886837	1.934008	1.321572	0.880497	0.763662	0.676015	0.619977	0.523333	0.498101	0.432007	0.362297
NDDC	US$M	16.50831112	2.011949	2.256789	3.03	0.919479	1.057808	1.098493	0.650959	0.927616	0.528904	0.252246	1.049671	0.610274	0.488219	0.488219	0.325479	0.211562	0.179014	0.154603	0.07093	0.058413	0.05424	0.045896	0.037551
ADJUSTED PROFIT		718.4332367	-69.0769	-77.4831	-104.03	72.69621	87.01727	91.47332	60.76178	90.00958	52.27823	25.58743	113.0425	67.92807	56.41478	56.95932	39.37536	26.28285	22.84376	20.52792	21.74384	18.40449	17.56369	15.27252	12.84032
Loss Carried Forward																									
Opening Balance			0	-69.0769	-146.56	-250.59	-177.894	-90.8765	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Assessed Loss For The Year			-69.0769	-77.4831	-104.03	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Utilized Loss			0	0	0	72.69621	87.01727	90.87653	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Closing Balance			-69.0769	-146.56	-250.59	-177.894	-90.8765	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSESSABLE PROFIT		718.4332367	0	0	0	0	0	0.596793	60.76178	90.00958	52.27823	25.58743	113.0425	67.92807	56.41478	56.95932	39.37536	26.28285	22.84376	20.52792	21.74384	18.40449	17.56369	15.27252	12.84032
EDUCATION TAX		14.08692621	0	0	0	0	0	0.011702	1.191407	1.764894	1.025063	0.501714	2.21652	1.331923	1.106172	1.116849	0.772066	0.51535	0.447917	0.402508	0.42635	0.360872	0.344386	0.299461	0.251771
FINAL ASSESSABLE PROFIT		704.3463105	0	0	0	0	0	0.585091	59.57037	88.24469	51.25316	25.08571	110.826	66.59615	55.30861	55.84247	38.60329	25.7675	22.39584	20.12541	21.31749	18.04362	17.2193	14.97306	12.58855
Capital Allowance																									
Capital Allowance: Opening Balance			0	6.548346	17.86792	36.03385	52.52725	69.93146	83.80662	34.53639	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capital Allowance for the Year			6.548346	11.31958	18.16592	16.4934	17.40421	14.46025	10.30014	5.551937	4.985552	4.079381	4.458148	4.207331	3.755916	3.746981	3.71786	2.885149	2.47354	2.155565	0.832578	0.520956	0.316379	0.143124	0
Capital Allowance Utilised			0	0	0	0	0	-0.58509	-59.5704	-40.0883	-4.98555	-4.07938	-4.45815	-4.20733	-3.75592	-3.74698	-3.71786	-2.88515	-2.47354	-2.15556	-0.83258	-0.52096	-0.31638	-0.14312	0
Closing Balance: CA Carried forward			6.548346	17.86792	36.03385	52.52725	69.93146	83.80662	34.53639	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CAPITAL ALLOWANCE RECOVERABLE		138.5222498	0	0	0	0	0	0.585091	59.57037	40.08833	4.985552	4.079381	4.458148	4.207331	3.755916	3.746981	3.71786	2.885149	2.47354	2.155565	0.832578	0.520956	0.316379	0.143124	0
CHARGEABLE PROFIT		565.8240607	0	0	0	0	0	0	0	48.15636	46.26761	21.00633	106.3678	62.38882	51.55269	52.09549	34.88543	22.88236	19.9223	17.96985	20.48491	17.52267	16.90292	14.82993	12.58855
CITA		113.1648121	0	0	0	0	0	0	0	9.631272	9.253522	4.201267	21.27357	12.47776	10.31054	10.4191	6.977086	4.576471	3.98446	3.59397	4.096982	3.504533	3.380585	2.965986	2.51771
NET CASHFLOW (NCF)		591.181	-69.077	-77.483	-104.030	72.696	87.017	91.462	59.570	78.613	42.000	20.884	89.552	54.118	44.998	45.423	31.626	21.191	18.411	16.531	17.221	14.539	13.839	12.007	10.071
CUMMULATIVE NCF			-69.0769	-146.56	-250.59	-177.894	-90.8765	0.585091	60.15546	138.7689	180.7685	201.653	291.2054	345.3238	390.3218	435.7452	467.3714	488.5625	506.9738	523.5053	540.7258	555.2649	569.1036	581.1107	591.1815
NPV	10%	$145.30																							
IRR	21%																								
PAY BACK	5	Years																							
PSC GAS CASH FLOW			2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
DESCRIPTION	UNIT	TOTAL																							
PRODUCTION	BCF		0	0	0	41.245	47.45	49.275	29.2	41.61	23.725	11.315	47.085	27.375	21.9	21.9	14.6	9.49	8.03	6.935	6.205	5.11	4.745	4.015	3.285
GROSS REVENUE	US$M	1357.114	0	0	0	113.8169	134.2133	142.8597	86.77406	126.7444	74.07318	36.21039	154.449	92.04083	75.47348	77.36032	52.86288	35.2199	30.54649	27.04058	24.79906	20.93333	19.92404	17.28027	14.49187
COST RECOVERY	US$M	457.963	67.06	75.23	101.00	22.41	25.67	28.03	13.92	19.58	11.65	5.68	21.90	12.72	10.01	10.79	7.10	4.71	4.06	3.41	3.90	2.73	2.18	1.79	2.44
ROYALTY	US$M	33.928	0	0	0	2.845423	3.355332	3.571493	2.169352	3.168609	1.85183	0.90526	3.861225	2.301021	1.886837	1.934008	1.321572	0.880497	0.763662	0.676015	0.619977	0.523333	0.498101	0.432007	0.362297
NDDC	US$M	16.508	2.011949	2.256789	3.03	0.919479	1.057808	1.098493	0.650959	0.927616	0.528904	0.252246	1.049671	0.610274	0.488219	0.488219	0.325479	0.211562	0.179014	0.154603	0.07093	0.058413	0.05424	0.045896	0.037551
TAXES	US$M	127.252	0	0	0	0	0	0.011702	1.191407	11.39617	10.27859	4.702981	23.49009	13.80969	11.41671	11.53595	7.749152	5.091821	4.432377	3.996478	4.523331	3.865405	3.724971	3.265447	2.769481
NET CASH FLOW/ PROFIT GAS		721.463	-69.08	-77.48	-104.03	87.64	104.13	110.15	68.85	91.67	49.77	24.67	104.15	62.60	51.67	52.61	36.36	24.33	21.12	18.80	15.68	13.76	13.47	11.75	8.88
CUMMULATIVE			-69.08	-146.56	-250.59	-162.95	-58.82	51.33	120.17	211.84	261.61	286.28	390.43	453.03	504.70	557.32	593.68	618.01	639.12	657.93	673.61	687.37	700.84	712.58	721.46
NPV	10%	$206.11																							
IRR	25%																								
PAYBACK	5	YEARS																							
ALLOCATION OF PROCEEDS																									
Revenue (Gas)		1357.113975	0	0	0	113.8169	134.2133	142.8597	86.77406	126.7444	74.07318	36.21039	154.449	92.04083	75.47348	77.36032	52.86288	35.2199	30.54649	27.04058	24.79906	20.93333	19.92404	17.28027	14.49187
Royalty (Gas)		33.92784938	0	0	0	2.845423	3.355332	3.571493	2.169352	3.168609	1.85183	0.90526	3.861225	2.301021	1.886837	1.934008	1.321572	0.880497	0.763662	0.676015	0.619977	0.523333	0.498101	0.432007	0.362297
NDDC Due		16.50831112	2.011949	2.256789	3.03	0.919479	1.057808	1.098493	0.650959	0.927616	0.528904	0.252246	1.049671	0.610274	0.488219	0.488219	0.325479	0.211562	0.179014	0.154603	0.07093	0.058413	0.05424	0.045896	0.037551
NDDC Recoverable			0.000	0.000	0.000	8.218	1.058	1.098	0.651	0.928	0.529	0.252	1.050	0.610	0.488	0.488	0.325	0.212	0.179	0.155	0.071	0.058	0.054	0.046	0.038
Available Gas		1306.678	0.000	0.000	0.000	102.753	129.800	138.190	83.954	122.648	71.692	35.053	149.538	89.130	73.098	74.938	51.216	34.128	29.604	26.210	24.108	20.352	19.372	16.802	14.092

Table 4.1. Production Profile of the Asset and Cost Structure

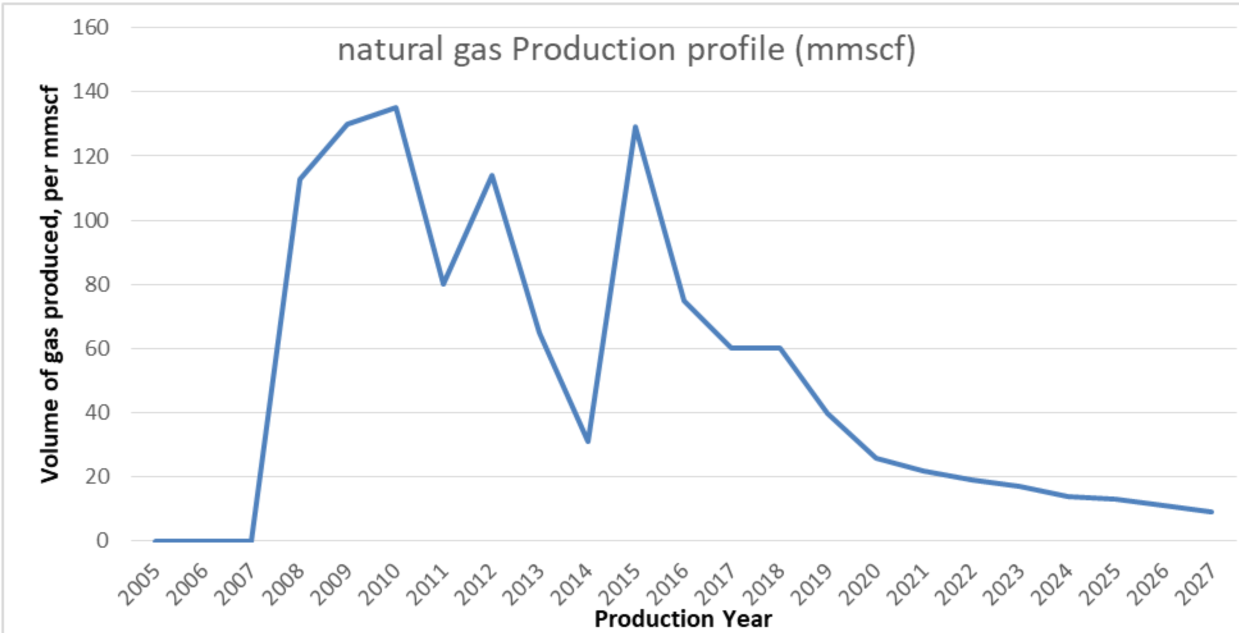


Figure 4.1. Production profile of the un-named associated gas field deep-offshore Nigeria

Source: Author's Computation

4.3 Proposed Fiscal Regime

The fiscal terms and applicable rates given in Table 4.1 are the proposed rates developed from this study to encourage fiscal competitiveness while optimising government's take and in turn, the country's retention of the wealth from this resource.

From the proposed regime, all terms prior to production are negotiable. Only signature bonuses are imposed on the contractor which acts as an upfront benefit to the government before production begins. Though signature bonuses are regressive, they are negotiable in this case. Production allowance which is 20.0% of the gas value produced for the year is only allowed after loss carry from previous capital expenditures are recovered.

The royalty rate is calculated on a production and price-based sliding scale. When the R-factor is less than 1.5, full cost recovery is achieved; when it is more than 1.5, only 60.0% of the initial investment is recouped.

Companies Income Tax (CIT) is fixed at 30.0% while Education tax is fixed at 2.0% and NDDC levy is fixed at 3.0% of the annual budget.

An evaluation of the proposed fiscal provisions is given in Table 4.3:

Table 4.2: Proposed Fiscal Terms for Natural Gas Under PSCs

FISCAL TERM	PROPOSED RATE		DESIGN
Allocation mechanism	Profit-Gas-Split based		Bid term/negotiable
Govt. Participation			Negotiable
Work program			Bid term/negotiable
Duration/relinquishment			Ten years exploration and ten years development
Bonuses			
Signature Bonus	$3M-$5M		Based on estimated reserves in place
Development Bonus	NIL		
Production Bonus	20% of gas value		
Royalty (production based)	2% 3% 4%	< 50 bcf 50- 100 bcf > 100 bcf	Sliding scale- production based
Royalty (price based)	0.5% 0.5% 0.75%	$0-$3/Mscf $3-$5/Mscf >$5/Mscf	
Cost Recovery	0-1.0 1.1-1.5 >1.5	100% 100% 60%	Sliding scale- r factor based. Costs to be carried forward until full recovery.
Profit Gas Split	60/40		Fixed (in favor of the concessionaire)
Taxes			
Cit	30%	Xx	Fixed- paid by contractor
Education	2%	Xx	Fixed-paid by contractor
Nddc	3%	Xx	Annual budget-based

Source: Author's Computation

Table 4.3: Fiscal Provisions and Features

S/N	Fiscal Term	Feature	Remark
1	Allocation mechanism and work program	Biddable/Negotiable	
2	Signature bonus $3M~$5M Production allowance (20% of gas value)	Negotiable Fixed	Regressive Progressive
3	Royalty (2%)	Sliding scale (production and price based)	Regressive
4	Cost recovery	R-factor based	Progressive
5	CIT	Fixed	Regressive
6	NDDC and EDT	NDDC- budget based EDT- Can only be deducted after assessed profit for the year is positive	Regressive

Source: Author's Computation

Table 4.3 suggests that the fiscal provisions of the proposed regime are overall-progressive. This means these terms will effectively capture justifiable government takes from the projects in varying economic situations during the life of the project. This feature encourages fiscal competitiveness especially in the global scene where several host governments compete to attract funds for development of their resource.

Progressive taxation that rises with rising prices, output, and cost recoupment is the hallmark of a competitive fiscal system. In addition, fiscal arrangements must be reasonable in light of the interests of both the contractor and the host government.

Both the internal rate of return (the rate of return on the project to the contractor when the net present value is zero) and the net present value (representing the discounted cash flows over the whole life of the project) must be positive for the project to be profitable. The government is exempted from responsibility from the very start to the very conclusion. The contractor may earn back all the money it spent on the project by using certain recovery procedures like loss carry forward and cost recovery based on the R-factor. Both the government and the contractor may hope to make money off of the project if its net present value (the cumulative NCF discounted at a particular rate) is positive. The petroleum industry is known for its 70/30 profit split, with the majority going to the government of the host nation.

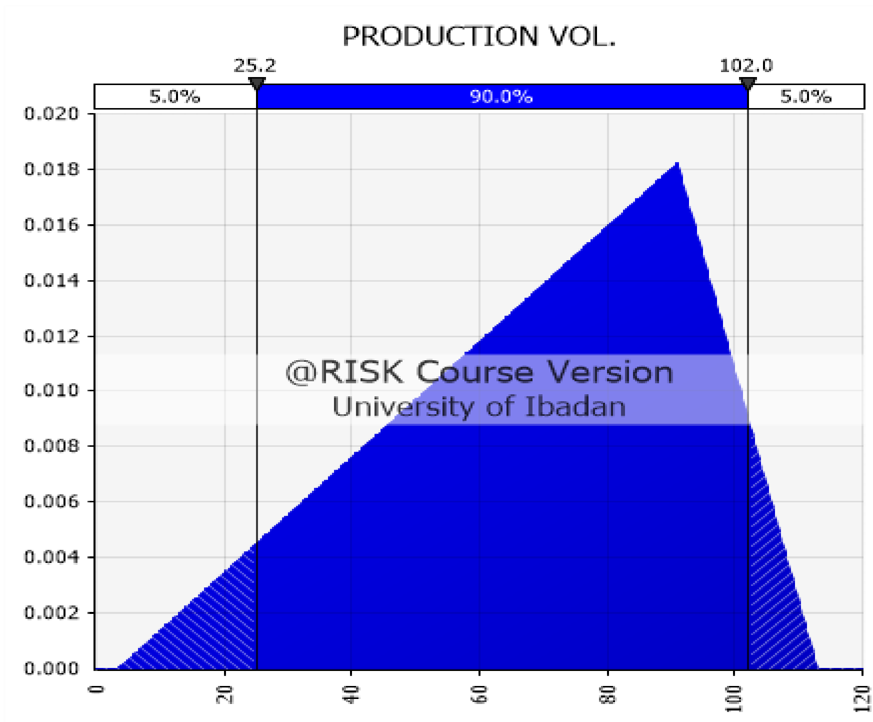
Probabilistic Analysis

In analysing cash flow models over the life of projects especially in the petroleum industry which last over long periods, (25 years or more), there needs to be consideration for eventual changes in input variables of the model which will occur. As operations go on, changes such as rises and drops in forecasted production levels and prices will definitely occur, especially in response to dynamic market and industry conditions beyond the control of the contractor. These will show significant impact in projected cash inflow while capital expenditures have already been made. It is therefore imperative that for a robust model and analysis to be achieved, the likely changes in input variables over likely statistical distributions are inputted in the model for analysis. This is the probabilistic approach in cash flow modelling using sensitivity analysis.

Sensitivity analysis is a technique which allows the analysis of changes in assumptions used in forecasts. It estimates the responsiveness of outputs as the assumptions of the model changes. Sensitivity analysis helps us challenge assumptions made in a model, it checks the validity of input variables and its significance in producing the output of the specified model. The process starts off by specifying statistical distributions of the various inputs. Simulations are run based on iterations of variable inputs along the range of values of their statistical distributions. These are conducted against changes in mean values of the output.

Input variables in our cash flow model are costs (opex and capex), NDDC levy, production volume and natural gas price. While the output variable is the discounted net cash flow from the project.

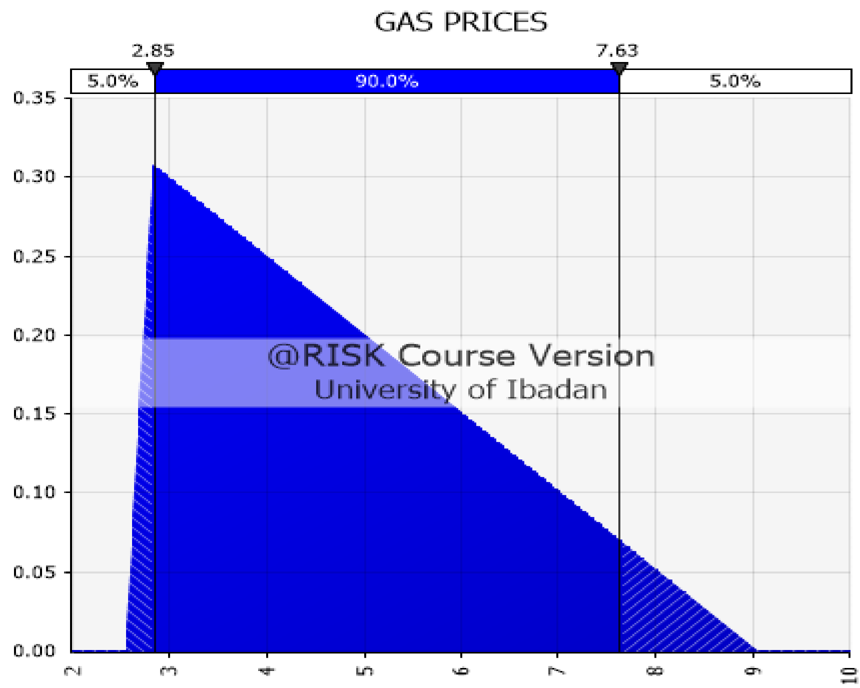
The statistical distributions for the input variables chosen are triangular distributions which show their observed minimum value, most likely and maximum values. The chosen distribution for each variable is shown below:



Statistics	Triang
Minimum	3.30
Maximum	113.00
Mean	69.10
Mode	91.00
Median	72.66
Std Dev	23.69
Skewness	-0.4756
Kurtosis	2.4000
Left X	25.2
Left P	5.0%
Right X	102.0
Right P	95.0%
Dif. X	76.78
Dif. P	90.0%
1%	13.11
2.5%	18.81
5%	25.23
10%	34.32
20%	47.16
25%	52.34
30%	57.02

Fig. 4.2. Probability distribution of Production Volume Input

Source: Author's Computation using @Risk



Statistics	Triang
Minimum	2.5470
Maximum	9.0500
Mean	4.8090
Mode	2.8300
Median	4.5529
Std Dev	1.5005
Skewness	0.5619
Kurtosis	2.4000
Left X	2.85
Left P	5.0%
Right X	7.63
Right P	95.0%
Dif. X	4.7768
Dif. P	90.0%
1%	2.6827
2.5%	2.7615
5%	2.8511
10%	3.0164
20%	3.3615
25%	3.5421
30%	3.7289

Fig. 4.3. Probability distribution of natural Gas Prices Input

Source: Author's Computation using @Risk

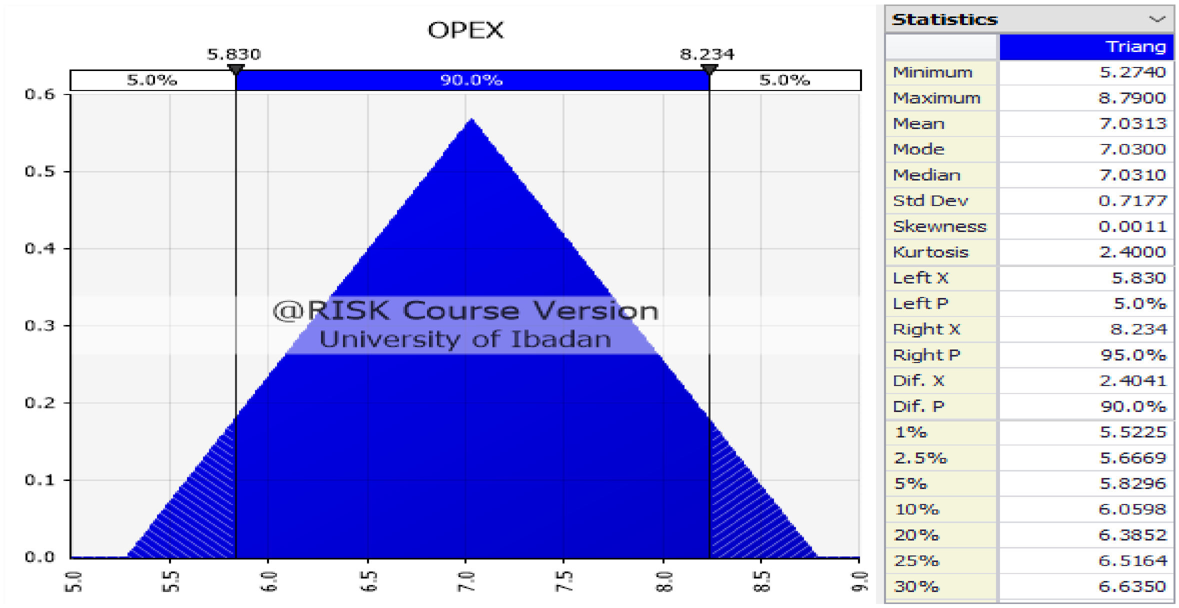
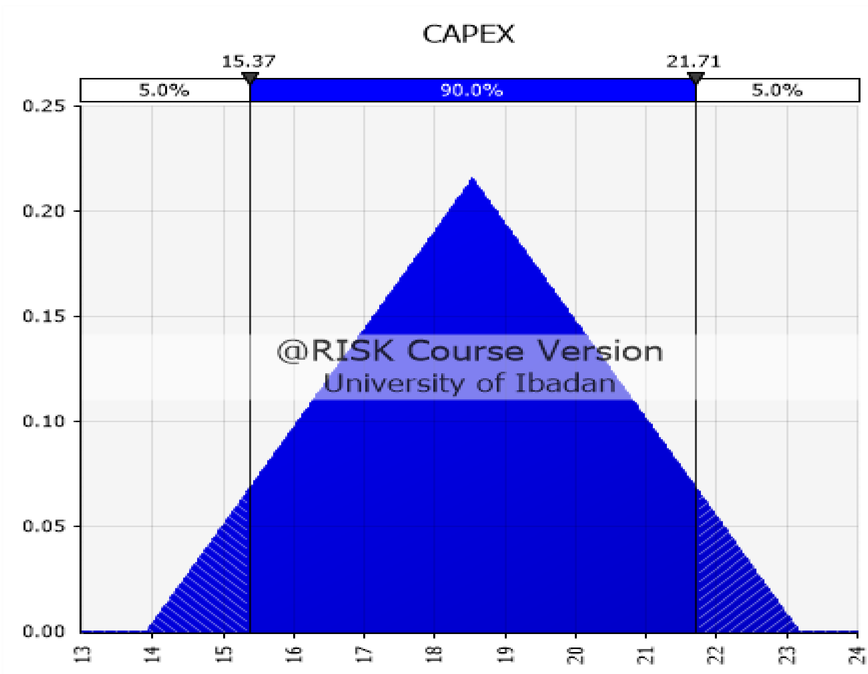


Fig. 4.4. Probability distribution of OPEX Input

Source: Author's Computation using @Risk



Statistics	Triang
Minimum	13.9100
Maximum	23.1800
Mean	18.5433
Mode	18.5400
Median	18.5425
Std Dev	1.8922
Skewness	0.0011
Kurtosis	2.4000
Left X	15.37
Left P	5.0%
Right X	21.71
Right P	95.0%
Dif. X	6.3386
Dif. P	90.0%
1%	14.5651
2.5%	14.9459
5%	15.3749
10%	15.9817
20%	16.8398
25%	17.1857
30%	17.4983

Fig. 4.5. Probability distribution of CAPEX Input

Source: Author's Computation using @Risk

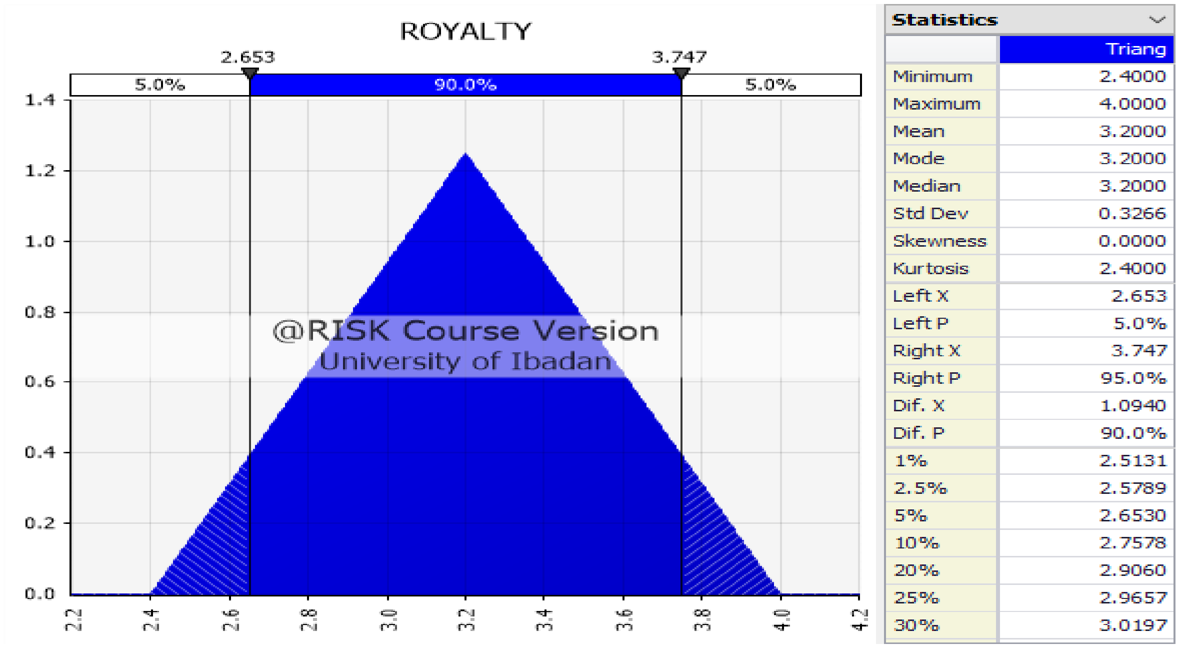


Fig. 4.6. Probability distribution of Royalty Input

Source: Author's Computation using @Risk

Using the defined variable distributions for inputs above, a monte carlo simulation of 10,000 iterations was conducted to evaluate sensitivity of changes in inputs along their established limits and how they impact on changes in output (NCF) mean. It is important to note that in estimating the maximum and minimum values of the input variables, a rule of thumb of 25% more and 25% less of the most likely value for each variable was applied. The tornado chart and spider graphs were used to highlight the results obtained. These charts graphically illustrate the most significant inputs or variables in our model with the greatest impact on the output of the model.

4.4 Results of Cash Flow Analysis:

Table 4.4. Deterministic Results of the Profitability of the Project

S/N	INDEX	RATE	VALUE (US$M)
1.	NPV	10%	122.13
2.	IRR	20%	
3.	Payback Period	6 years	
4.	Contractor Take	53%	
5.	Government Take	47%	
6.	Pre- Tax NPV	10%	174.73
7.	Pre- Tax IRR	22%	

Source: Author's Computation

Table 4.4 is a summary of the indices computed using the DCF analysis of an associated gas field, deep offshore Nigeria. This is conducted using a base price of US$ 2.5 per Mscf for natural gas, production and cost profiles as obtained from the contractor.

Results of the cash flow analysis report an NPV of $122.13 million at 10.0%, Internal Rate of Return of 20.0% and a Payback period of 6 years.

With an average industry ROR of 12.0%, a positive NPV and a payback period of 6years, the project is economically viable based on the economic indices highlighted.

Pre and post indicators of NPV and IRR suggest that the tax regime is not neutral since there is a significant decrease in earnings, after taxes have been deducted. The contractor and government takes of 53.0% and 47.0% respectively suggests that the project is high yielding for the contractor since the industry profit split for PSCs is 70%/30% in favor of the host government. On the other hand, the government's take is relatively high, considering the government enjoys a free carry all through the life of the project.

Savings Index Computation:

Assuming a dollar is saved on costs, the resulting division of (undiscounted) earnings on the dollar to the contractor in a single accounting period is obtained below:

A	$1.00	Assumed Cost savings
B	$1.00	Profit Gas (increased by $1.00)
C	$0.60	Govt. Share of Profit (60%)
D	$0.40	Contractor's Share of Profit (40%)
E	$0.088	Taxes (22%)
F	$0.312	Contractor's Share Saved

The Contractor's Earnings on the dollar saved = $0.312 (F) - This means the Contractor will save about 31 cents or 31.0% on every dollar saved. This savings index is moderate in consideration of industry provisions in other climes. In countries like Ireland, the savings index is about 85.0% on every dollar saved in favor of the contractor while countries like Saudi Arabia have savings indexes of about 12.0% for contractors. This discrepancy can be attributed by extension to the need by several governments to attract investments in their natural resources for technological or commercial reasons.

Figure 4.7, shows the government and contractor takes from the project -it is seen that the government earns higher returns from the project as soon as production begins. This shows that the proposed regime is indeed progressive and favours the host government since it enjoys a free carry from project inception and does not incur any costs during production.

Figure 4.8 shows the tornado chart which is a sensitivity presentation of the impact of changes in input variables on output. In this case, production volumes, natural gas prices, royalty and capex are the most sensitive inputs to be considered when analysing profitability of the project.

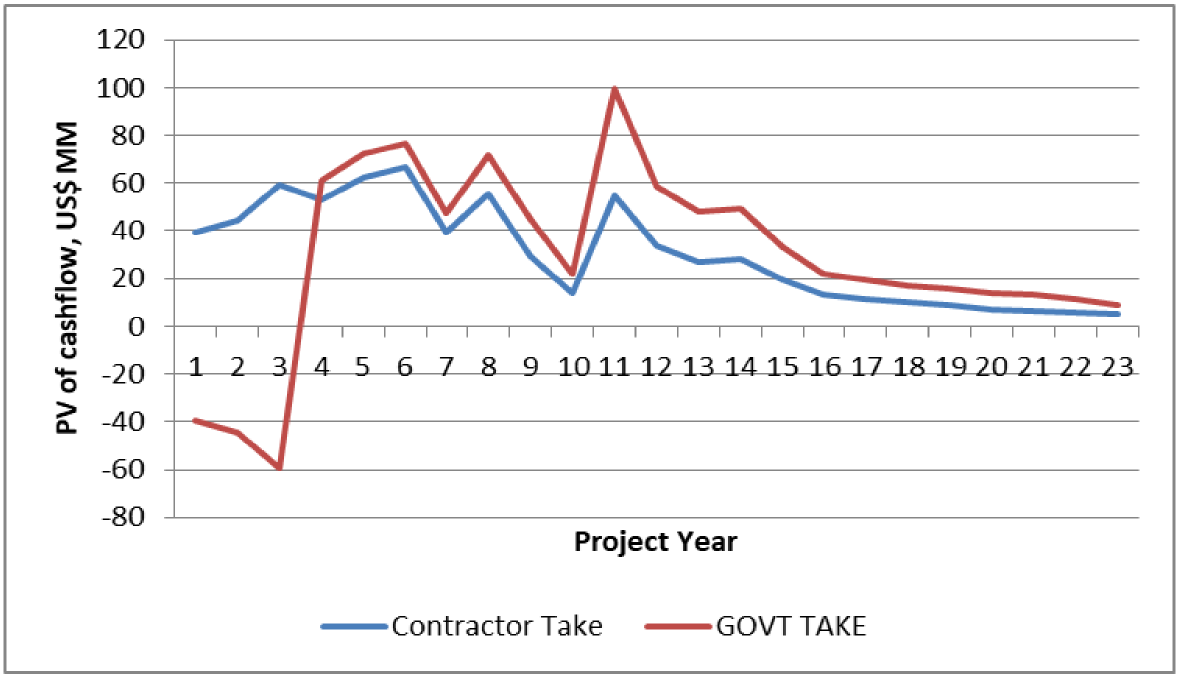


Figure 4.7. Parties' Takes from inflows of the project
Source: Author's Computation

Sensitiviy Charts:

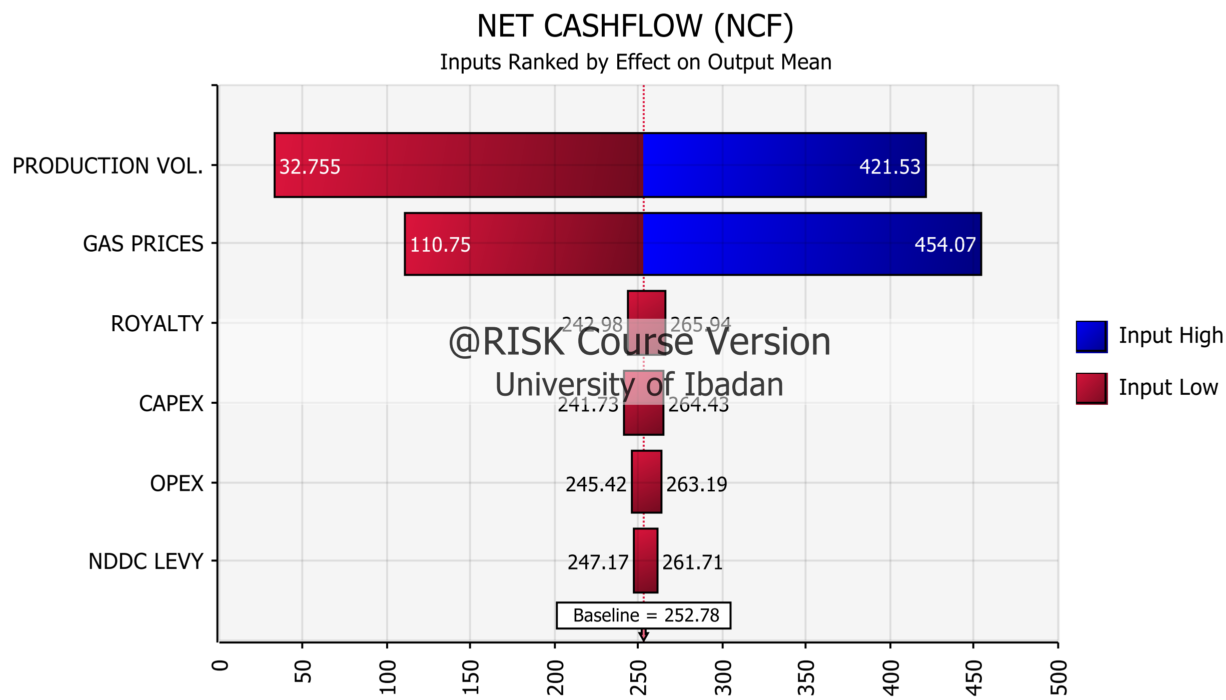


Figure 4.8. Tornado chart showing sensitivity of inputs to changes in output mean

Source: Author's Computation using @Risk

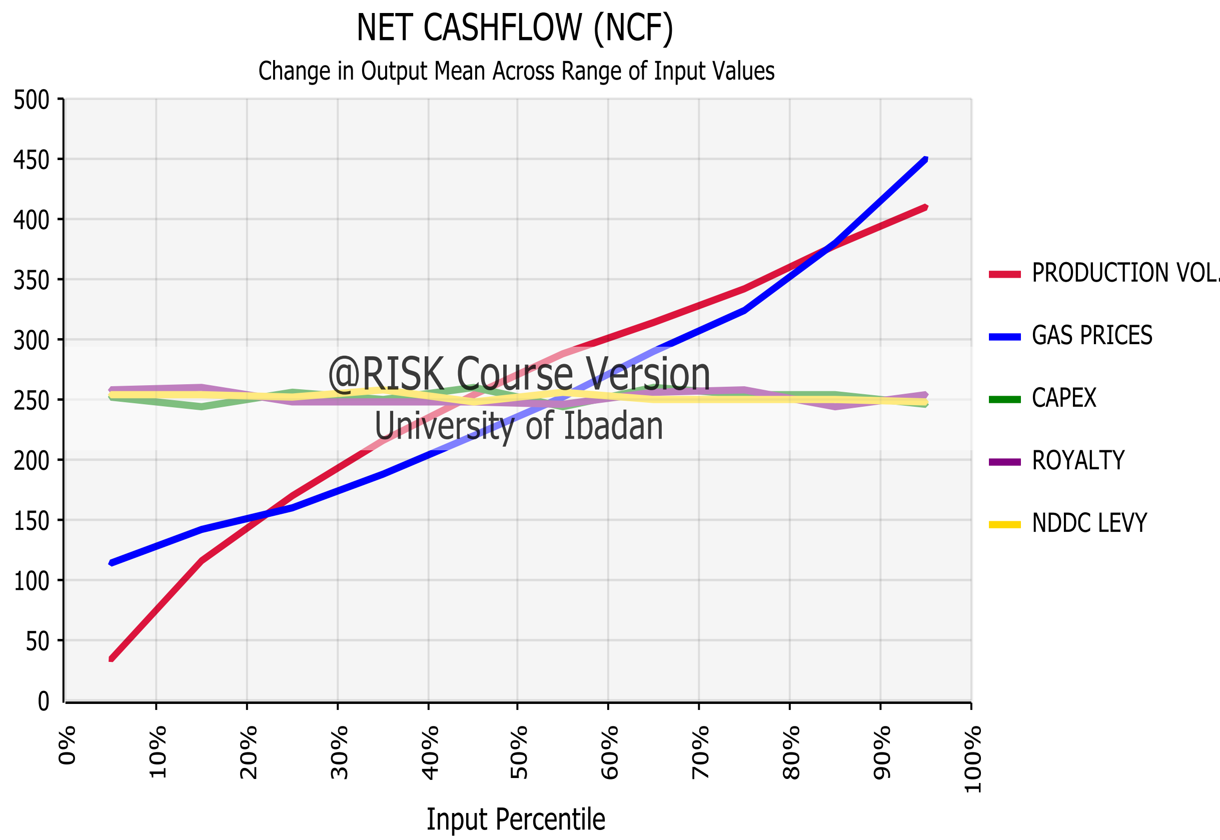


Figure 4.9. Spider Graph Showing Sensitivity of Input Variables to Changes in Output Mean

Source: Author's Computation using @Risk

Figure 4.9 illustrates the most responsive variables to changes in the profitability of the project. The spider graph shows and orders the input variables according to their sensitivity to changes in project profitability. From the graph, it is seen that production volumes, natural gas prices, CAPEX and royalty are the most sensitive variables in the project. This confirms apriori expectations as changes in natural gas production volumes and prices will affect the project's economic viability as much as the price and quantity of a typical commodity with elastic demand. CAPEX and royalty also significantly impact the profitability if the project as expected because high capital outlay of projects and a high rate of a profit sensitive royalty will reduce the profits to be shared amongst parties from the project. NDDC levy OPEX show lower impact on the output and is expected since the NDDC levy is dependent on the annual budgeted costs and costs are closely monitored and restricted.

From the charts above, close attention should be paid to ensure stability of production levels which is mostly a technical issue and stability of natural gas prices, which is a market risk beyond the control of the contractor or a single host government.

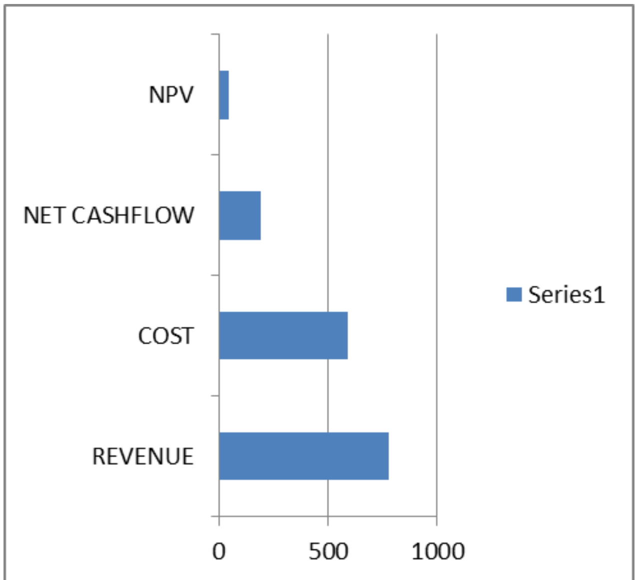
4.4.1 Results of Comparative Analysis

This section compares the input data and outputs of our model with the results obtained from the fiscal provisions in the PIA (2021). Table 4.5 presents the summary of deterministic economic results obtained from the project under both fiscal regimes analyzed. Here, the PIA (2021) gives an NPV (@10%) of $ 105.21 million while the proposed regime gives an NPV (@10%) of $ 122.13 million. The internally generated rate of return of the project is 18.0% for PIA (2021) which is significantly lower than the provisions of the project under the proposed fiscal regime which is 20.0%. Payback period is 6 years for the contractor under the PIA (2021) and 6 years under the proposed regime. Government take under the PIA (2021) is 42% while it is 47.0% under the proposed fiscal regime.

Table 4.5. Comparison of Deterministic Output Values on Project Economics

S/N	INDEX	PIA (2021) PSC GAS PROVISIONS	PROPOSED PSC GAS PROVISIONS
1.	NPV @10%	US$ 105.21m	US$ 122.13m
2.	IRR	18%	20%
3.	Payback Period	6 Years	6 Years
4.	Government Take	42%	47%
5.	Contractor TAKE	58%	53%
6.	Pre-tax NPV	US$ 153.29m	US$ 174.73m
7.	Pre-tax IRR	21%	19%

Source: Author's Computation



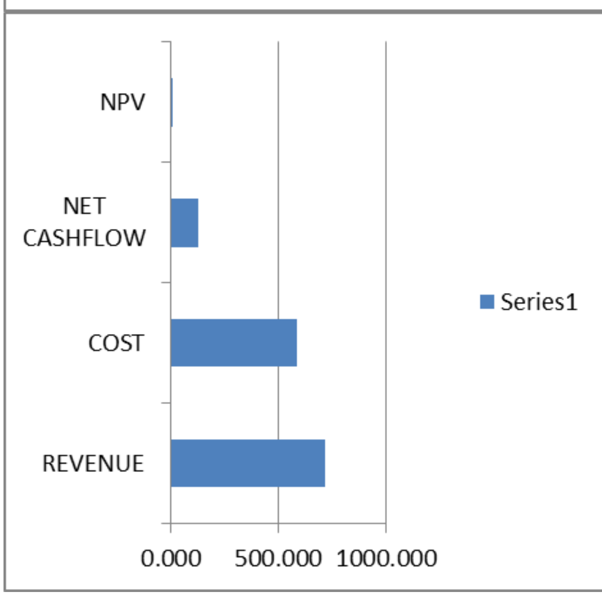


Figure 4.10. Comparison of Contractor' Economics

Contractor economics under the PIA (2021)

Contractor economics under the proposed regime

Figure 4.10 shows contractor' economics under both fiscal regimes. The contractor's NPV values (@10%) are \$42.08 million and \$12.366 million under the PIA (2021) and the proposed fiscal regime respectively. The internal generated return (IRR) of the contractor under the PIA (2021) and the proposed fiscal regime are 13.0% and 18.0% respectively. The Net Cash flow due the contractor under the PIA (2021) and the proposed fiscal regime are \$129.83 million and \$236.29 million respectively.

The contractor economic indices highlighted in this section suggest that the contractor earns less under the proposed fiscal regime than under the PIA (2021). This should however not serve as a deterrent to investments since the contractor take is 53.0% which is well above the global industry average of 30/70% in favour of the host government. Also, the positive and higher IRR value from the project which is higher than 12.0%- global industry hurdle rate and a cost recovery mechanism (R-factor) based should encourage contractors to partake in such ventures.

Figure 4.11 shows that the government takes under both regimes are negative in the first three years of the project. This is because the project did not make any commercial production within those years. From the fourth year however, production began and government takes under both regimes were positive and remained so until the projected end of the economic life of the project. From table 4.11, it shows that government takes from each year of production is higher under the proposed fiscal regime than it is under the PIA (2021). This continues towards the end of the field's life, when production has gotten to its plateau and begins declination.

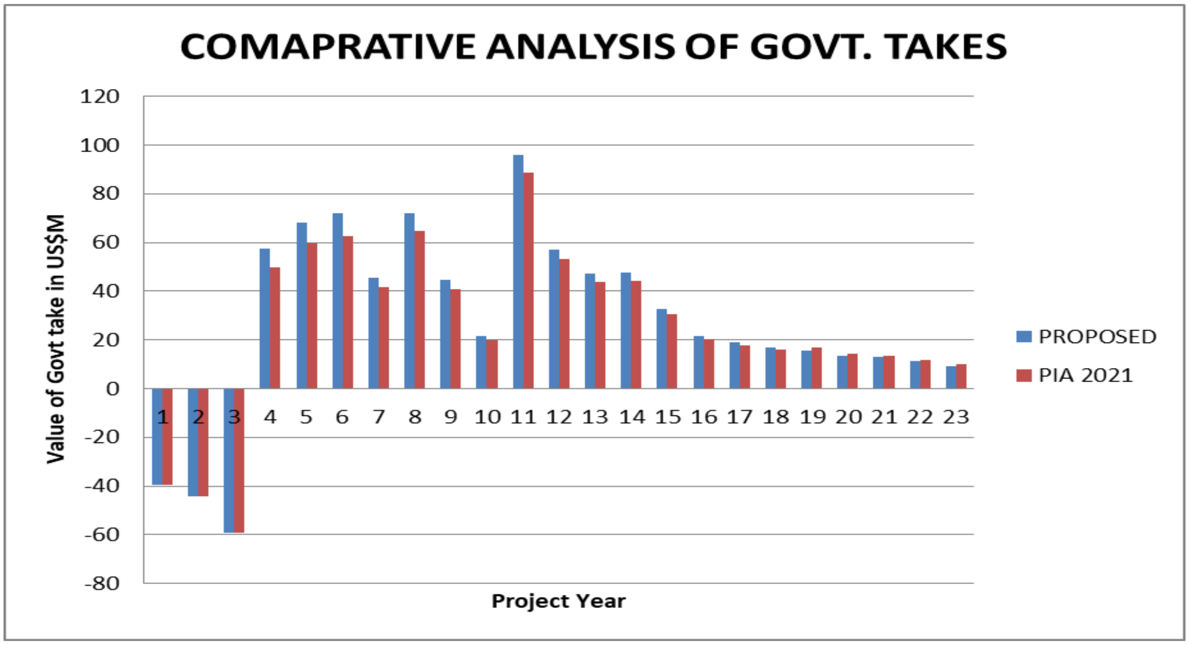


Figure 4.11. Comparison of Government Takes under the PIA (2021) and the Proposed Fiscal Regime.

Source: Author's Computation

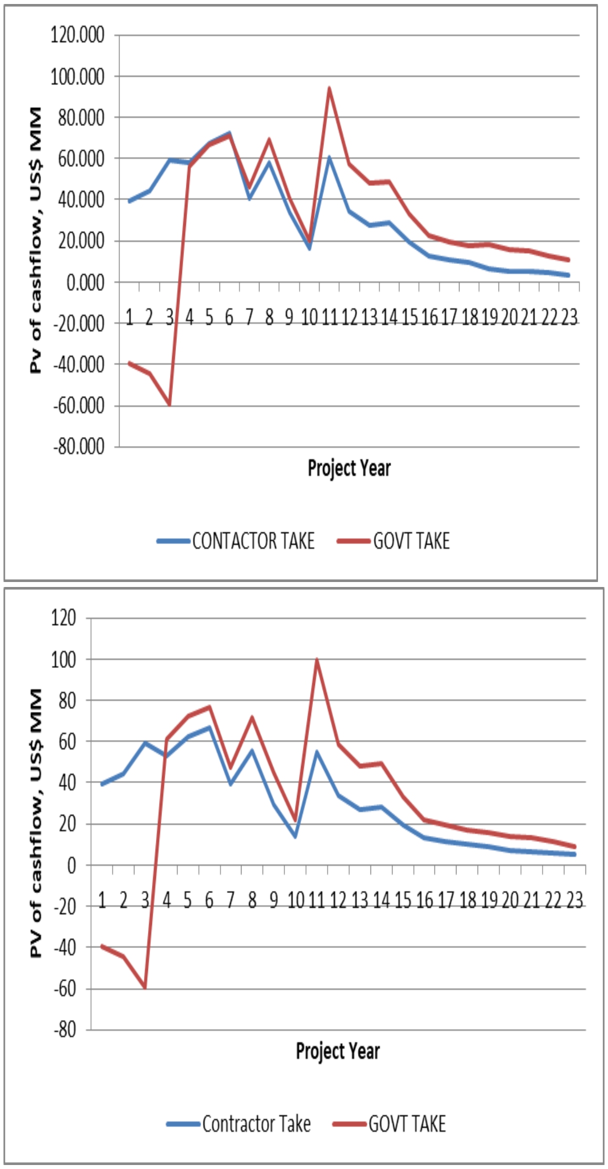


Figure 4.12. Comparison of Parties' Takes

Parties take under the PIA (2021)

Parties take under the proposed fiscal regime

From Figure 4.12, it can be seen that under the PIA (2021), the host government starts earning higher takes than the contractor in the seventh year while under the proposed fiscal regime, the host government starts earning higher takes from the beginning of economic production from the field. This suggests that the PIA (2021) is more front loaded than the proposed fiscal regime as investors will have to attain full cost recovery before the host government begins to earn higher takes than the contractor.

Table 4.6 shows the comparison of contractors' share of profit when $1.00 is saved under both regimes examined in this section. The savings index as noted earlier is a technical tool used in determining the efficiency of a fiscal regime with regards to incentivising contractors and the government to be prudent with costs. Under the PIA (2021), it is seen that the contractor only saves about 25 cents which is 25 pecent of the $1.00 saved on costs. The proposed regime saves about 31 cents which is approximately 30 percent of the $1.00 saved. This difference is mainly because of the inclusion of the host community development tax imposed by the government in the PIA and the market-sensitive tax burden in the proposed regime given that the royalty rate imposed is based on a sliding scale. These factors account for a tax rate on savings of 38.0% in the PIA and 22% in the proposed regime.

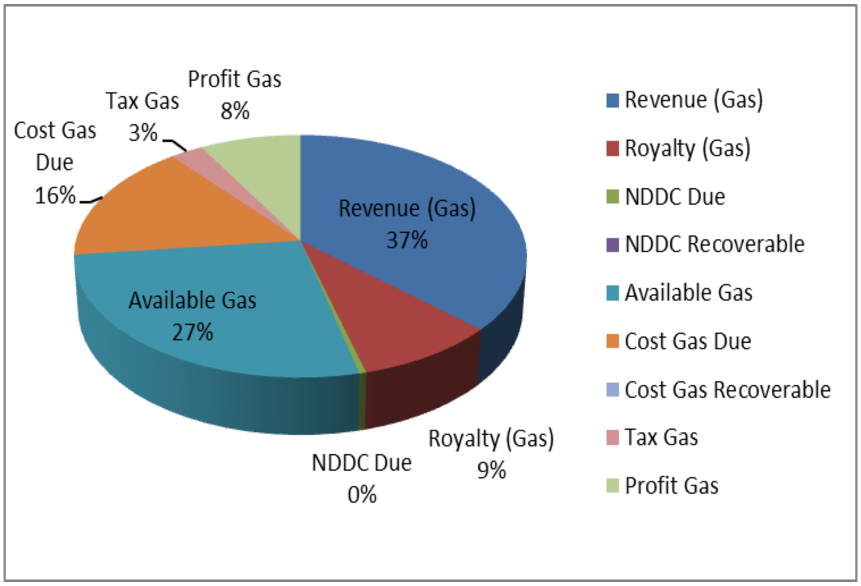
Figure 4.13 shows the allocation of proceeds from the project under the fiscal provisons from the PIA (2021) and the proposed fiscal regime. From Figure 4.13, profit gas under the PIA (2021) is 8.0% while profit gas under the proposed fiscal regime is 12.0%. Revenues from the PIA (2021) and the proposed regime are 37.0% and 35.0% respectively. Royalty under the PIA (2021) and the proposed fiscal regime is 9% and 3% respectively. Available Gas is 27.0% under the PIA (2021) and 31.0% under the proposed fiscal regime. Cost gas on the other hand is 16% under the PIA (2021) and 15.0% under the proposed fiscal regime. The PIA (2021) offers 3.0% of tax gas while the proposed fiscal regime offers 4.0% of tax gas.

Figure 4.13 shows that the proposed fiscal regime offers higher profits and higher volumes of available gas from the allocation of proceeds while it offers lesser revenues and royalty than the provisions in the PIA (2021).

Table 4.6: Saving index Comparison:

S/N	TERM	PIA 2021	PROPOSED REGIME
1.	COST SAVINGS OF $1	$1.00	$1.00
2.	PROFIT GAS	$1.00	$1.00
3.	GOVT SHARE OF PROFITS	$0.60 (60%)	$0.60 (60%)
4.	CONTRACTOR SHARE OF PROFITS	$0.40	$0.40
5.	TAXES	($0.152) 38%	($0.088) 22%
6.	CONTRACTOR SHARE OF PROFIT	$0.248	$0.312

Source: Author's Computation



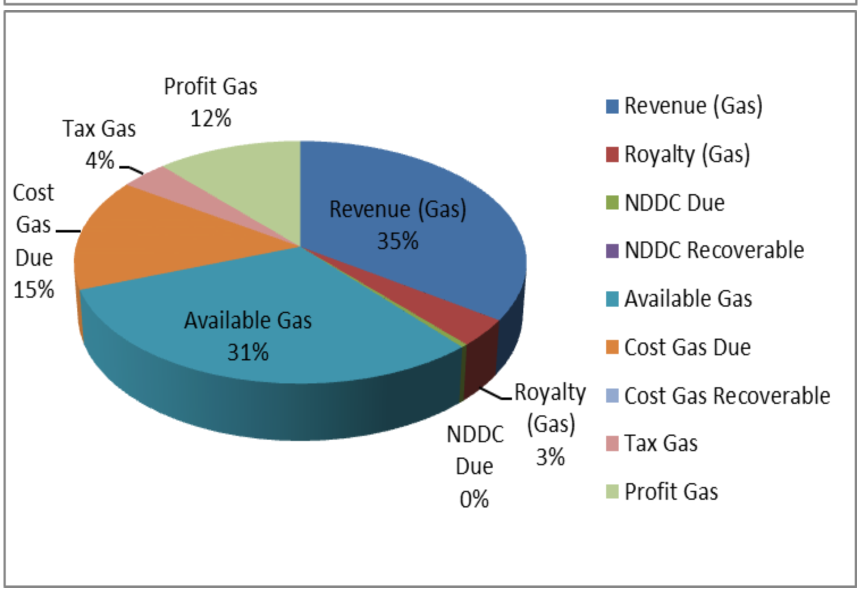


Figure 4.13. Pie Charts Showing the Allocation of Proceeds from the Project

Under the PIA 2021

Under the proposed fiscal terms

Source: Author's Computation

From the results analyzed in this section, it is seen that the PIA (2021) fiscal terms for PSC gas are harsher than the proposed PSC gas terms as the proposed fiscal terms offer more profitable project economics for the host government. The PIA (2021) offers reduced returns from the project as the host government will have a lower party-take and a longer time before earning higher shares of proceeds from production than the contractor.

These clear distinctions in benefits due the contractor and host government under both fiscal regimes examined are mainly due to the market sensitivity of the royalty rate – sliding scale, lower rate of royalty in the proposed fiscal regime and the transferred incidence of taxation –the host community development tax, from the contractor to the Concessionaire. These clearly suggest that the host government is made better off under the fiscal terms of the proposed fiscal regime than under the fiscal provisions in the PIA (2021).

4.5 Discussion of Findings

In their analysis of fiscal regime designs, Tordo (2006), Mian (2004), and Adedayo (2014) all agree that fiscal regimes need to be progressive, neutral, and stable in order to strike a good balance between the needs of the host government and those of the contractor. Figures 4.10, 4.11, and 4.12 demonstrate that the proposed fiscal regime results in a larger government take than under the PIA (2021). This proves that the proposed fiscal system is more progressive than the PIA. This is due to the fact that, under the proposed system, the government enjoys a higher percentage of the project's revenues in periods of high natural gas prices and/ or high production volumes and vice versa.

Table 4.5 shows a significant difference in Pre- and Post-Tax NPV and IRR estimates for the proposed fiscal regime and the provisions in the PIA (2021). Theoretically, this suggests that both regimes are not neutral- neutral fiscal regimes are not to have a significant difference and Pre- and Post- tax economic indices. In this case, it is understood that the government needs to attract economic benefits of the project and the best means to achieve this especially in Nigeria, is to utilize tax tools such as royalty and CITA –these ensure that the government gets economic returns from the project for the benefits of its citizens irrespective of the outcome of the project for any year.

The savings rates under the two systems are shown in Table 4.6. The proposed fiscal regime has a greater savings index than the PIA (2021). This provides an incentive for the contractor to practice frugal behaviour by making every dollar count. This shows that the proposed fiscal system would promote thrifty resource use, discouraging wasteful economic activities by contractors like gold-plating and over-invoicing that result in monetary losses for the state. In comparison to the PIA (2021), this aspect of the projected fiscal system shows more stability.

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CHAPTER FIVE

SUMMARY, CONCLUSION AND RECOMMENDATIONS

5.1 Summary

The study set out to evaluate the profitability of developing and producing natural gas in linked gas fields in deep offshore Nigeria under PSCs with that of producing crude oil. Since the discovery of both crude oil and natural gas in 1957, there have been no dedicated funds set aside for the development of natural gas in Nigeria. Natural gas development under PSCs is still uncertain, despite the PIA (2021) suggesting some financial alterations from the existing status quo in reference to crude oil operations and JVs for natural gas. This study suggests that in addition to crude oil, natural gas should be extracted from the deep offshore Nigerian PSC-governed gas resources.

The proposed PSC terms for gas in this research were compared to the recently approved petroleum industry bill (PIA 2021). Based on this research, a standalone fiscal regime for natural gas development presented in this study provides more economic benefits to the federal government of Nigeria than the provisions of the PIA (2021). The objectives of this study are addressed in sections 4.3; and 4.4.

5.2 Conclusion

Unlocking Nigeria's abundant natural resources especially in the natural gas sector require a clear cut, globally competitive fiscal regime to drive investments. In cognizance of increased competition from old and emerging producers of the resource around the world, Nigeria needs to more than develop -implement a world class efficient process of administration and management of operations and conduct in the industry to boost investor confidence and in turn long term sector growth. This will encourage a strong and resilient industry which will increase and stabilize earnings of the federal government and contribute to the overall Nigerian economy.

5.3 Contributions to Knowledge

The design of an independent fiscal regime for natural gas development in deep offshore Nigeria to the best of our knowledge has not been done before; this study therefore serves as a background literature for the identification of natural gas as a standalone commodity in petroleum property evaluation in Nigeria and Africa.

This study will serve as a useful tool for the government and investors in ascertaining what is due each party in relation to the development of associated gas- deep offshore under production sharing contracts in Nigeria. It will also serve as valuable research material in petroleum offshore development economics for researchers and governments in Africa.

5.4 Recommendations

From the findings of this study, it is recommended that the relevant policy making institutions consider the provisions made in the proposed PSC gas terms as a tool to fill the void in the PIA (2021). This will serve as a guide for investors in that sub sector of the gas market who are still left out as to what the fate of their investments are and what future investments in this sector will yield.

In this regime of fiscal competitiveness for funds to develop resources, it is highly recommended that the Federal Government of Nigeria consider the provisions of this proposed fiscal regime in its new Petroleum Industry Law which is believed and intended to be more market-friendly than previously existing regimes. The dynamic nature of this proposed fiscal regime ensures that the Federal Government and Contractors optimize accruals from natural gas exploitation at all times given prevailing market demands, global industry standards and expectations.

5.5 Suggestions for Further Research

The study was conducted using secondary data obtained from the sampled associated gas field and FPSO production and expenditure profile for the project. These documents are regarded highly classified and are unavailable to the general public. The Nigeria Extractive Industries Transparency Initiative (NEITI) should therefore work towards increased transparency of contracts and operations in the Nigerian petroleum industry so decisions taken by the government and other stakeholders can be independently analyzed for research and management purposes.

For further studies, researchers should look into areas such as:

- An analysis of the proposed fiscal regime in this study on Non-associated gas fields. This will further inform the economic viability of our model and further inform the federal government on establishing independent fiscal terms for natural gas development, totally separated from crude oil and condensates.

- An analysis of fiscal provisions and project economics for PSC gas projects using alternative funding options. This is a needed area of research as new funding arrangements are being reached every day, away from traditional PSCs and equity funding.

- An analysis of natural gas development in deep offshore Nigeria using real options approach.

Studies of this nature will help improve the scanty literature on natural gas investments in Nigeria and Africa.

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Appendix 1

Features of Flexible, Neutral and Stable Fiscal Regimes

Definition	Advantage
A flexible fiscal regime is one that ensure that when economic conditions change, the host country's government should be able to collect a fair share of economic rent.	As market and project conditions evolve over time, progressive rent extraction mechanisms provide greater stability by reducing the frequency of renegotiation.
A neutral fiscal regime is one which neither encourages over investment nor deters investment that will otherwise take place.	Neutrality's benefit is that it promotes economic efficiency. There is no effect on resource distribution due to a neutral tax. For an investing firm, a tax is neutral if the order in which the investment results are ranked before and after taxation does not change. When a tax has no effect on the flow of capital into or out of a certain sector, we say that it is "neutral" with regard to that sector.
A stable fiscal regime is one which does not change over time or its changes are predictable.	• There are two types of stability clauses: "freezing" clauses, which keep the contract/financial terms the same for the duration of the contract or for a certain period of time, and "equilibrium" clauses, which allow the contract terms to be adjusted over time so that one party is not harmed or benefited unduly by a change in circumstances. • When evaluating investment options, solid and predictable contractual and fiscal conditions are crucial for industries with lengthy time cycles and considerable upfront expenditures, which has evident implications on the future prospects of the nation. Because of the oil and gas industry's lengthy project cycles and high degree of resource pricing and project production unpredictability, this is especially true.

Source: Tordo, 2006

Appendix 2

Fiscal Provisions for regime design:

Accelerated capital cost (CAPEX) allowances	Costs in acquiring petroleum assets are depreciated over the useful life of the asset using the following methods: a. straight-line method- reduces equal amounts from the value of the asset over a fixed period; b. decline balance- depreciated using the remaining balance of the value of the asset at end of each year; c. double-declining balance- doubles straight-line depreciation for the balance of the value of the asset each year; d. sum-of-year digits: is derived using an inverted scale which is the ratio of the number of digits in a given year divided by the total number of all years digits; e. unit of production- here, the capital cost of the asset, after deduction of the accumulated depreciation and salvage value, is multiplied by the ratio between the total production in a year and the recoverable reserves remaining at the beginning of the tax year.
Depletion Allowances	This allowance is a deduction allowed to investors from gross income derived from exploiting assets with finite and exhaustible deposits. This is to compensate for the high-risk inherent in the industry and to encourage investors in searching for other reservoirs for further exploration and possible development.
Interest deduction rules	Project finance costs on petroleum investments are deductible from taxable income and qualify for cost recovery. Inter-company interests are also recoverable and tax-deductible if treated on arms-length basis.
Loss carry forward	This is a provision for losses incurred to be 'carried forward' to future years in offsetting tax liability. Loss carry forward provisions are usually unlimited, but limited cases are usually for 5 to 7 years from the year it is incurred.
Investment credits	This is an additional allowance governments may allow investors recover on tangible capital expenditures incurred. They are however,

Source: Author's compilation